Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

EXHIBIT 1
APPLICATION OVERVIEW AND ADMINISTRATION

Table of Contents

List of Appendices

List of Tables

Application

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

AND IN THE MATTER OF an Application by Welland Hydro Electric System Corp. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2025.

Welland Hydro Electric System Corp.
(the "Applicant" or "WHESC")

APPLICATION FOR APPROVAL OF 2025 ELECTRICITY DISTRIBUTION RATES

EB-2024-0058

Filed: August 23, 2024

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1 Application Overview and Administration

1.1 Application

The applicant, Welland Hydro Electric System Corp., is referred to in this application as “Applicant” or ‘WHESC”. The Applicant hereby applies to the Ontario Energy Board (the “OEB” or the “Board” interchangeably) pursuant to Section 78 of the OEB Act for approval of its proposed distribution rates and other charges, effective May 1, 2025.

The Applicant is an Ontario Corporation with its offices in the City of Welland. The Applicant carries on the business of distributing electricity in its service territory which consists of the City of Welland. WHESC’s 2025 Cost of Service Application (EB-2024-0058) (the “Application” or “COS” interchangeably) presents evidence demonstrating how WHESC will develop, operate, and maintain its distribution system to ensure it provides safe, reliable, and efficient service to its customers.

The period for this COS covers nine years with historical information for the 2017-2023 period, the 2024 Bridge Year, and a one-year forward test period – the 2025 Test Year. The Distribution System Plan (“DSP”) provides a summary of WHESC’s asset planning process and objectives, a review of WHESC’s asset-related operational performance over an eight-year historical period, and a forecast of capital expenditures over the 2025-2029 period. WHESC’s last COS and DSP was filed on October 28, 2016 for rates effective May 1, 2017.

The application includes nine Exhibits, including this Exhibit 1, as follows:

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

WHESC has prepared this application in Accordance with the following:

- The Application has been prepared pursuant to the Report of the Board, Renewed Regulatory Framework for Electricity Distributors; A Performance Based Approach, issued October 18th, 2012 (the “RRFE”);

- Unless specifically stated otherwise in the Application, the Applicant followed Chapter 1, and Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on December 15th, 2022 (the "Filing Requirements") in preparing this application;
- The Applicant has prepared a consolidated DSP in accordance with Chapter 5 of the OEB's Filing Requirements;
- The Application has been prepared in accordance with direction provided to Licensed and Rate-regulated Electricity Distributors in the OEB's letter dated April 11th, 2024 regarding *"Filing Requirements for Electricity Distributor Rate Applications for 2025 Rates"*;
- WHESC acknowledges that the OEB may publish an update to its cost of capital parameters for 2025 distribution rates and that this may affect the Revenue requirement that the Applicant has requested in this Application;
- The OEB's Handbook for Utility Rate Applications, issued October 13, 2016; and
- WHESC has not deviated from these filing requirements and provides a checklist of the filing requirements as Appendix 1-G, which identifies the specific reference in the Application where relevant information is provided.

1.2 Application Summary and Business Plan

WHESC provides a summary of key elements of this Application in the subsections that follow. The application is underpinned by WHESC's Business Plan, which is included in Appendix 1-A.

The application includes a planned decrease in rates of 2.8% for a typical residential customer in WHESC's service territory. WHESC's OM&A and capital expenditures of the period of 2017 through to 2024 ensured the continued safe and reliable operation of the distribution system while managing asset health and accommodating customer growth. Despite inflationary pressures in recent years, WHESC's rate reduction is a testament to WHESC's prudent management practices to balance system performance with customer affordability.

Business Plan Themes

Meeting Current and Future Customer Requirements

WHESC's customer base is growing. WHESC's customer count including only the residential and general services classes, totalled 25,753 at the end of 2023. This represents an increase of 11.7% from 2017 levels. This drives WHESC's level of System Access based investments but also requires investment in other areas to sustain and improve reliability performance as the system expands. WHESC recognizes that customer expectations are changing as the energy transition progresses. Investments in grid modernization are strategic in ensuring the distribution system is capable of supporting transition.

WHESC regularly engages with its customers, including specific engagement in support of this Application. The results of this engagement is viewed as one of the most important factors in understanding customer's needs and supplements the Electrification Strategy Study procured in partnership with GridSmart City Cooperative member LDCs.

Distribution System Plan in Alignment with Strategic Objectives and Goals

The current Distribution System Plan ("DSP") was developed in alignment with WHESC's strategic objectives and goals. RRFE outcomes are mapped to these objectives in support of WHESC's investment planning cycles. WHESC's second Asset Condition Assessment ("ACA") conducted in 2023, is a key driver to the planning process. WHESC's level of system renewal investments correlate to updated asset health indices.

WHESC's corporate goals place a heavy weighting on health and safety performance, minimizing environmental impact, and asset performance with a tie to operational efficiency and affordability. The key objective is to maintain or improve reliability of the distribution system while accommodating growth. The identified programs and projects within the DSP are designed and prioritized to meet this objective and maximize the contribution to meeting intended RRFE outcomes.

Managing Risk

A key theme of WHESC's business plan is the objective of maintaining cost performance while improving reliability and reducing risk. Key areas of risk identified in the business include:

- Ability to accommodate growth
- Supply capacity
- Energy transition/electrification impacts
- Climate change
- Asset Health
- Cybersecurity

WHESC has been an active stakeholder in Integrated Regional Resource Planning ("IRRP") and the subsequent Regional Infrastructure Plan ("RIP") to ensure that the LDC's expanding capacity requirements will be met moving forward. WHESC has identified solutions to bridge a capacity gap that will exist through the forecast period of the DSP. WHESC agrees with the IESO's preferred alternative to addressing supply needs at the transformer station and transmission level.

WHESC has engaged customers to understand short term utilization changes related to the energy transition and electrification impacts. WHESC has also performed studies to research adoption rates specific to the WHESC service area. In this application, WHESC discusses data integration and Advanced Distribution Management System ("ADMS") tools used to improve grid visibility in accommodation of the energy transition and DER adoption. Planned capital investments take into consideration additional capacity requirements stemming from electrification in the forecast period.

WHESC's business plan highlights the approach taken in anticipation of climate change impacts. Grid modernization and 24 x 7 system control capability are identified as two key components WHESC believes are crucial to managing significant weather events and the complexity of a distribution system with bi-directional flows. Additionally, DSP investments to sustain asset health are strategic in preparing the system to perform through such events.

WHESC completed its latest ACA in 2023 in support of the DSP. The business plan recognizes the identified areas of poor asset health, driving system renewal investments to form the majority of net capital expenditures.

Cybersecurity remains a risk for all Ontario LDCs. Information systems continue to expand to meet the everchanging needs of customers, increasing the cyber-risk profile. WHESC has identified expenditures in this application designed to improve WHESC's cybersecurity posture, leveraging a shared services arrangement to manage cost impact.

Maintaining Cost Performance

In 2020, WHESC's benchmarked efficiency ranking moved the LDC to "Cohort 1" as described in Section 1.6.1.2 of this Exhibit. While managing the risks identified above, a key deliverable of the business plan continues to be monitoring performance against industry benchmarks to ensure WHESC remains in Cohort 1. WHESC forecasts its efficiency ranking as part of the business planning process to assess whether a significant change in total OM&A plus capital cost against predicted costs will occur. WHESC's business plan demonstrates that WHESC is likely to remain in Cohort 1.

The key elements of the Application are discussed in the following subsections.

1.2.1 Revenue Requirement

WHESC is requesting approval of its proposed service revenue requirement in the amount of $13,845,188, an increase of 35.5% over the 2017 Board Approved Amount of $10,214,159. Table 1-1 shows a comparison of the Revenue Requirement calculations between the 2017 Board Approved Proxy to the 2025 Test Year.

Table 1-1: Service Revenue Requirement

Service Revenue Requirement	2017 Board Approved	2025 Test Year at Proposed Rates	Variance vs 2017 Board Approved	Variance %	Reference
OM&A	6,800,000	8,823,658	2,023,658	29.8%	Exhibit 4 - 4.2.1
Depreciation	1,415,729	2,095,996	680,267	48.1%	Exhibit 2 - 2.4
PILs	91,096	315,602	224,506	246.5%	Exhibit 6 - 6.2
Return on Debt	725,013	912,604	187,591	25.9%	Exhibit 5 - 5.1.2
Return on Equity	1,182,321	1,697,328	515,007	43.6%	Exhibit 5 - 5.1.2
Total	10,214,159	13,845,188	3,631,029	35.5%	
Rate Base Average Fixed Assets	29,501,967	42,034,971	12,533,004	42.5%	Exhibit 2 - 2.1
Rate Base Working Capital Allowan	4,163,200	4,037,990	- 125,210	-3.0%	Exhibit 2 - 2.1
Rate Base	33,665,167	46,072,961	12,407,794	36.9%	

- OM&A has increased 29.8% over eight years, a compound average growth rate ("CAGR") of 3.3%. OM&A cost drivers are detailed in Exhibit 4, Section 4.2.1. It is notable that OEB inflationary factors over the eight-year period total 24.5% compounded, and WHESC has experienced an 11.5% increase in customer count over the period. The primary cost drivers are listed in Section 4.2.2 of the exhibit. These primary drivers consist of costs associated with Salaries, Wages and Benefits, Billing Contract Services, Information Systems, Locates, Stores Material, Postage, ADMS Software and Tree Trimming.
- Depreciation has increased as WHESC has continued to invest in the distribution system, particularly in the renewal of deteriorated assets and the accommodation of new connections. This increase is detailed in Exhibit 4, Section 2.4.
- The Payments-in-Lieu of Taxes ("PILS") amount is based on the regulatory taxable income of $875,350 in the 2025 Test Year as detailed in Exhibit 6, Section 6.2.
- The 2017 OEB Approved average net fixed asset value was $29,501,967, compared to $42,034,971 in the 2025 Test Year. Details regarding the increase in net fixed assets are provided in Exhibit 2, Section 2.1. As a result of WHESC's net assets growing by $12,533,004, there has been an increase in the return on Rate Base from in-service capital additions since the 2017 COS Application.
- In the 2025 Test Year, WHESC seeks a Return on Equity of 9.21% (the current Board approved rate). WHESC acknowledges that this is subject to change at such time that the 2025 Cost of Capital Parameters are issued by the OEB.

1.2.2 Load Forecast Summary

WHESC used the same regression analysis methodology approved by the OEB in its 2017 COS Application (EB-2016-0110) and updated the analysis for actual power purchases to the end of 2023. Table 1-2 provides a summary of WEHSC's load and customer growth from 2014 to the 2025 Test Year. Exhibit 3 provides the details and assumptions supporting the forecasted number of customers.

Table 1-2: Summary of Load and Customer/Connection Forecast

Year	Billed Actual (GWh)	Growth (GWh)	Percent Change (%)	Billed Weather Normal (GWh)	Growth (GWh)	Percent Change (%)	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections									
2017 Board Approved				360.5			30,582		
2014	380.9			384.3			29,944		
2015	356.4	(24.5)	-6.4%	358.5	(25.8)	-6.7%	30,128	184	0.6%
2016	363.4	7.0	2.0%	354.8	(3.7)	-1.0%	30,347	219	0.7%
2017	353.7	(9.7)	-2.7%	358.8	4.1	1.1%	30,565	217	0.7%
2018	379.1	25.4	7.2%	369.9	11.1	3.1%	30,910	346	1.1%
2019	370.6	(8.5)	-2.2%	371.8	1.9	0.5%	31,266	356	1.2%
2020	364.6	(6.0)	-1.6%	363.2	(8.6)	-2.3%	31,606	341	1.1%
2021	368.5	3.8	1.1%	367.6	4.5	1.2%	32,121	514	1.6%
2022	377.1	8.6	2.3%	376.3	8.7	2.4%	32,609	488	1.5%
2023	370.8	(6.3)	-1.7%	380.4	4.1	1.1%	33,276	666	2.0%
2024 Bridge	380.4	9.6	2.6%	380.4	0.0	0.0%	33,679	404	1.2%
2025 Test	381.0	0.6	0.2%	381.0	0.6	0.2%	34,090	410	1.2%

Table 1-3 below provides a summary of WHESC's total load forecast.

Table 1-3: Summary of Total Load Forecast

Year	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Actual kWh Purchases		368,596,645	393,889,926	384,791,777	380,093,690	383,895,273	392,612,236	386,633,788		
Predicted kWh Purchases		374,426,765	390,694,844	381,803,843	387,589,449	388,275,738	390,620,164	382,872,652	395,877,443	396,543,028
% Difference between Actual and Predicted Purchases		1.6%	-0.8%	-0.8%	2.0%	1.1%	-0.5%	-1.0%		
By Class										
Residential										
Customers	21,025	20,987	21,242	21,580	21,927	22,396	22,849	23,410	23,762	24,119
kWh	165,052,031	153,825,741	170,461,439	165,806,296	179,914,470	182,892,382	182,644,897	177,391,636	184,759,792	187,443,401
General Service < 50 kW										
Customers	1,777	1,791	1,798	1,797	1,788	1,837	1,838	1,845	1,857	1,869
kWh	53,828,309	52,319,962	52,983,337	50,506,435	48,537,507	54,230,050	55,719,442	54,279,425	56,052,591	56,382,524
General Service 50-4,999 kW										
Customers	154	159	164	166	161	140	139	142	140	137
kWh	138,619,965	144,490,127	152,610,121	151,352,404	133,284,409	128,548,463	136,029,471	136,432,090	136,879,400	134,534,275
kW	390,496	397,736	413,412	415,535	381,721	349,225	357,213	353,804	375,641	369,205
Streetlights										
Connections	6,856	6,865	6,956	7,007	7,067	7,115	7,186	7,336	7,400	7,464
kWh	1,286,433	1,393,112	1,403,956	1,406,314	1,423,807	1,410,628	1,418,460	1,453,176	1,465,852	1,478,639
kW	3,582	3,890	3,915	3,924	3,960	3,934	3,955	4,057	4,111	4,147
Sentinel Lights										
Connections	509	500	487	454	406	378	345	342	326	311
kWh	749,437	729,133	675,874	583,837	535,935	481,895	422,907	419,671	400,619	382,432
kW	2,061	2,012	1,898	1,605	1,474	1,328	1,162	1,153	1,105	1,055
Unmetered Scattered Load										
Customers	261	262	263	262	258	256	252	200	194	189
kWh	963,825	958,727	956,107	952,930	940,979	919,365	895,494	851,915	827,752	804,273
Totals										
Customers/Connections	30,582	30,565	30,910	31,266	31,606	32,121	32,609	33,276	33,679	34,090
kWh	360,500,000	353,716,802	379,090,833	370,608,216	364,637,107	368,482,783	377,130,671	370,827,913	380,386,005	381,025,544
kW	396,139	403,638	419,225	421,064	387,154	354,486	362,331	359,014	380,857	374,407

Based on the load forecast methodology, the 2025 Test Year kWh forecast is 381,025,544 kWh, a 20,525,544 or 5.7% increase from the 2017 Board Approved amount. The forecasted average customers/connections count for all classes in the 2025 Test Year is 34,090, a 3,508 or 11.5% increase from the 2017 Board Approved amount. Table 1-4 summarizes the customer/connections and their respective consumption and demand compared to the 2017 Board Approved amounts. The forecasting methodology for the average number of customers and connections is based on the historic geomean.

Table 1-4: 2025 Test Year Compared to 2017 Board Approved

Rate Class	2017 OEB Approved			2025 Test Year			Difference		
	Volume (kWh)	Volume (kW)	Customers/ Connections	Volume (kWh)	Volume (kW)	Customers/ Connections	Volume (kWh)	Volume (kW)	Customers/ Connections
Residential	165,052,031	-	21,025	187,443,401	-	24,119	22,391,370	-	3,094
General Service < 50kW	53,828,309	-	1,777	56,382,524	-	1,869	2,554,215	-	92
General Service > 50kW	138,619,965	390,496	154	134,534,275	369,205	137	- 4,085,690	- 21,291	- 17
Unmetered Scattered Lo	963,825	-	261	804,273	-	189	- 159,552	-	- 72
Sentinel Lighting	749,437	2,061	509	382,432	1,055	311	- 367,005	- 1,006	- 198
Street Lighting	1,286,433	3,582	6,856	1,478,639	4,147	7,464	192,206	565	608
Total	360,500,000	396,139		381,025,544	374,407		20,525,544	- 21,732	

1.2.3 Rate Base and Distribution System Plan (DSP)

WHESC is proposing a rate base of $46,072,961 for the 2025 Test Year. This is an increase of $12,407,793 or 37% from the 2017 OEB approved rate base of $33,665,168 as shown in Table 1-5.

Table 1-5: 2017 OEB Approved to 2025 Test Year Rate Base

Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Gross Fixed Assets Opening Balance	60,061,122	60,076,227	61,761,845	63,513,224	66,525,782	68,659,138	71,741,776	75,146,376	78,690,992	82,482,689
Gross Fixed Assets Closing Balance	62,093,917	61,761,845	63,513,224	66,525,782	68,659,138	71,741,776	75,146,376	78,690,992	82,399,979	87,298,102
Average Gross Fixed Assets	**61,077,520**	**60,919,036**	**62,637,534**	**65,019,503**	**67,592,460**	**70,200,457**	**73,444,076**	**76,918,684**	**80,545,486**	**84,890,396**
Accumulated Depreciation Opening Balance	30,927,737	30,928,494	31,797,087	33,045,389	34,235,843	34,728,457	36,345,789	38,094,006	39,955,800	41,909,721
Accumulated Depreciation Closing Balance	32,223,368	31,797,087	33,045,389	34,235,843	34,728,457	36,345,789	38,094,006	39,955,800	41,873,880	43,801,128
Average Accumulated Depreciation	**31,575,553**	**31,362,790**	**32,421,238**	**33,640,616**	**34,482,150**	**35,537,123**	**37,219,897**	**39,024,903**	**40,914,840**	**42,855,424**
Average Net Book Value	**29,501,967**	**29,556,245**	**30,216,297**	**31,378,887**	**33,110,310**	**34,663,334**	**36,224,179**	**37,893,781**	**39,630,646**	**42,034,971**
Working Capital	55,509,328	49,340,353	49,364,782	51,453,946	58,643,847	52,039,816	52,941,130	51,852,250	52,542,277	53,839,862
Working Capital Allowance (%)	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**4,163,200**	**3,700,526**	**3,702,359**	**3,859,046**	**4,398,288**	**3,902,986**	**3,970,585**	**3,888,919**	**3,940,671**	**4,037,990**
Rate Base	**33,665,168**	**33,256,772**	**33,918,655**	**35,237,933**	**37,508,599**	**38,566,321**	**40,194,763**	**41,782,700**	**43,571,317**	**46,072,961**

WHESC's proposed gross capital expenditures for the 2025 Test Year are $5.658M (excluding capital contributions). This represents a $3.548M increase over the 2017 OEB approved capital expenditures of $2.110M, a 168% increase. Capital contributions have increased by $974,000, resulting in a net increase in capital spending of $2.573M. Table 1-6 details proposed capital expenditures by category.

Table 1-6: 2017 OEB Approved vs. 2025 Test Year Capital Expenditures

CATEGORY	Historical Period	Forecast	Difference	Difference
	2017	2025		
	$ '000	$ '000	$ '000	%
Gross System Access	140	1,577	1,437	1026%
Gross System Renewal	1,735	2,884	1,149	66%
Gross System Service	80	242	162	203%
Gross General Plant	155	955	800	516%
Gross Capital Expenditure	2,110	5,658	3,548	168%
Capital Contributions	-	- 974	- 974	0%
Net Capital Expenditure	2,110	4,683	2,573	122%
System O&M	$ 3,314	$ 4,705	$ 1,391	42%

WHESC's DSP is designed to support the achievement of the four key OEB established RRFE performance outcomes. WHESC has mapped its corporate goals and asset management objectives to the RRFE outcomes in support of the planning process.

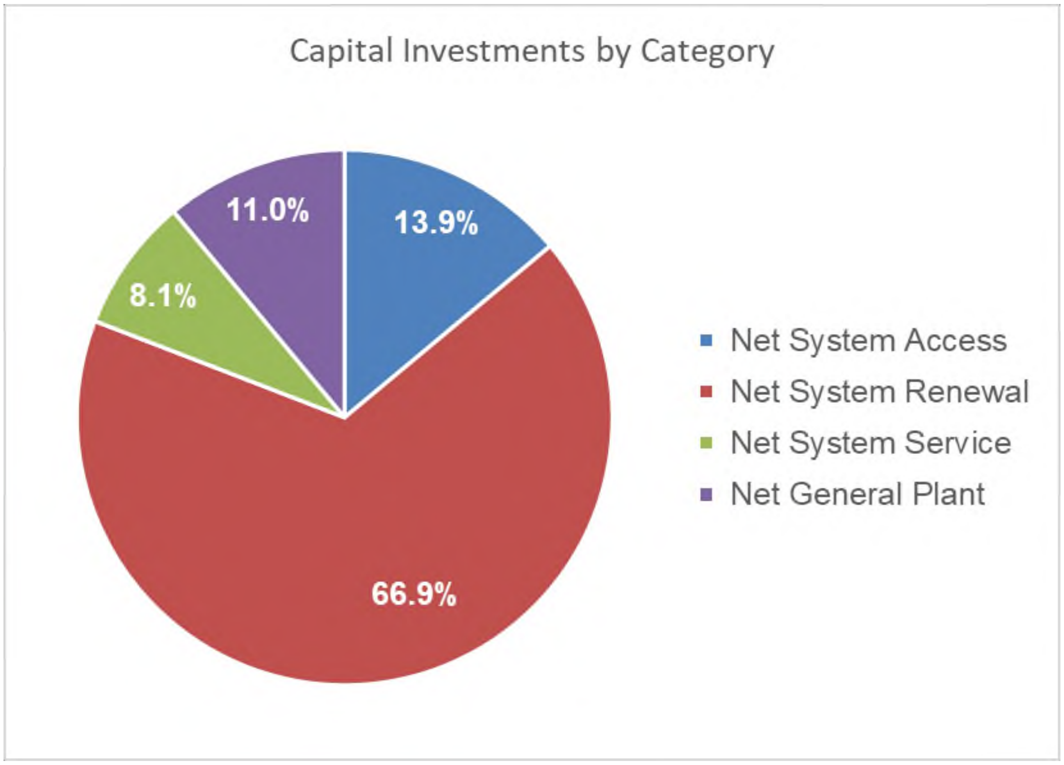
Table 1-7: Linkage of WHESC's Corporate Goals and Objectives to RRFE Outcomes

RRFE Outcome	Corporate Goal	Asset Management Objective
Customer Focus	Providing value to customers	Operational Efficiency and Affordability
Operational Effectiveness	Reliability and resilience	Asset Performance
		Environment
		Health and Safety Performance
		System Reliability
		System Capacity
		Meeting Regulatory and Legal Obligations
Financial Performance	Financial Integrity within OEB tolerances	Operational Efficiency and Affordability
		Meeting Regulatory and Legal Obligations
	Balanced approach to capital spending	Operational Efficiency and Affordability
Public Policy Responsiveness	Public Policy Compliance	Health and Safety Performance
		Meeting Regulatory and Legal Obligations

In the 2025 to 2029 forecast period of the DSP, 67% of planned net capital expenditures are in the System Renewal category of investment. While asset renewal investments are paced, a fundamental objective is to sustain system reliability by maintaining a prudent level of asset health. From recurring bi-annual surveys and most recently, feedback received on WHESC's DSP, system reliability ranks in the top two customer concerns, along with affordability. WHESC's current DSP incorporates a sufficient level of renewal and system service based investment to sustain reliability performance while managing growth.

WHESC's System Renewal investments are informed by the second Asset Condition Assessment ("ACA"), completed in 2023. The majority of the projects in the 2025 Test Year and balance of the period through to 2029 are designed to renew deteriorated assets, remove primary distribution from inaccessible rear-lot locations, and voltage convert to the 27.6 kV main system.

Table 1-8: 2025 – 2029 Capital Investments by Category



WHESC must keep pace with new connection requirements and as such has planned approximately 14% of net capital investment in the system access category. With accelerated housing development evident in the historical period, WHESC leverages information gleaned from routine participation in municipal planning activities to determine the expected level of expenditure required for System Access based investments. WHESC has compiled a listing of undeveloped lots based on known and committed developments which is included in the Business Plan, Appendix 1-A of this Exhibit. WHESC's planned investments in this category include residential services, general services, subdivision expansions, and metering installations.

Investments in General Plant are largely aimed at asset renewal expenditures. WHESC has completed needs assessments of fleet, facilities, and information systems to determine the necessary level of investment required to sustain function. General Plant based investments account for 11% of WHESC's planned net capital expenditure. Investments in renewing WHESC's fleet account for 57% as light duty vehicles and large trucks are replaced based on the results of the fleet condition assessment. Building improvements account for 20% of investment in this category based on the results of the facility condition assessment.

System service investment accounts for approximately 8% of WHESC's planned capital expenditure in the forecast period from 2025 through to 2029. Most of the planned investment in this category is directed at continued grid modernization initiatives. With growth in customer connections and planned conversion of existing load to the 27.6 kV system, WHESC continues to manage increased exposure on its nine distribution circuits. Continued improvement in system reliability is achieved through the deployment of automated recloser, sectionalizer, and switching devices. These deployments expedite restoration activities via SCADA through WHESC's system control service, available on a 24 x 7 basis.

While the planned system service based investments benefit system reliability, grid visibility is also enhanced. This positions WHESC's distribution system to manage increased connections related to electrification and DER deployment. WHESC continues to integrate real time data stemming from these investments into its analytical tools, namely SmartMap. This enables near real time analysis of power flow and asset utilization to make prudent operational and asset management decisions.

The DSP demonstrates a continued effort to pursue efficiencies through shared service approaches while improving system resiliency. WHESC collaborates with GSC partner LDCs to implement best practices when deploying grid automation based technology, deploying common standards and operating philosophies to maximize efficiency. WHESC has implemented a shared system control service designed to maximize the benefits of these technology deployments at a shared cost. WHESC intends to continue this approach in preparation for intensification of electrification activities and increased EV adoption rates. WHESC will be well positioned to manage increased penetration of DER and ready for the requirements of a Distribution System Operator (DSO), as this evolves.

1.2.4 Operations, Maintenance, and Administration Expenses

WHESC's OM&A Plan has been developed to ensure that it can continue to distribute electricity to its customers in a safe and reliable manner. The plan was formed with consideration of a number of factors including operational needs, legislative requirements, regulatory obligations, alignment with corporate goals, and ongoing engagement with our customers.

Table 1-9 summarizes changes to OM&A costs since WHESC's last Board approved Cost of Service Application in 2017 and the 2025 Test Year. As shown in this table, WHESC's increase in OM&A spending from the 2017 OEB Approved amount to the 2025 Test Year is $2,023,658 or 29.8%. Over the eight-year period, this amounts to a CAGR of 3.3%.

Table 1-9: OM&A - 2025 Test Year vs. 2017 OEB Approved

Expenses	2017 Board Approved	2025 Test Year	Variance
Distribution Expenses - Operation	1,498,740	2,035,874	537,134
Distribution Expenses - Maintenance	1,815,576	2,669,176	853,600
Total Operation & Maintenance	**3,314,316**	**4,705,050**	**1,390,734**
Billing and Collecting	1,467,344	1,765,877	298,533
Community Relations	144,123	62,438	-81,685
Administrative and General Expenses	1,874,217	2,290,294	416,077
Total Administrative & Customer Service	**3,485,684**	**4,118,608**	**632,924**
Total OM&A	**6,800,000**	**8,823,658**	**2,023,658**
% Change			29.8%

The OM&A costs in the 2025 Test Year reflect the resourcing mix and investments required to meet customer and broader public policy requirements for the duration of the 4th Generation IRM plan term. Without this level of resourcing and investments, WHESC will struggle to meet workload requirements, customer expectations, growth accommodation, and broader public policy requirements in 2025 and beyond. The increase is generally based on inflation impacts on labour and non-labour items, information systems and cybersecurity requirements, and increased costs to support WHESC's growing customer base.

Table 1-10 lists the primary cost drivers for increased OM&A amounts. Salaries, wages and benefits are the most significant cost driver. WHESC has implemented FTE reductions between 2017 and 2025, resulting in the cost increase associated with salaries, wages, and benefits to be limited to 13.1% over the eight-year period. This is well below inflation. The information systems and billing contract services cost drivers are in part related to WHESC's efforts to outsource and leverage shared service arrangements to maintain a reduced headcount. In these cases, the overall operating cost is lower as a result of outsourcing or cost sharing.

Table 1-10: Primary OM&A Cost Drivers

Primary Cost Drivers 2017-2025	Total
Salaries, Wages and Benefits	$ 517,807
Billing Contract Services	$ 168,348
Information Systems	$ 155,998
Locates	$ 145,037
Stores Material	$ 122,403
Postage	$ 100,618
ADMS Software	$ 93,863
Tree Trimming	$ 80,073
Total	**$ 1,384,147**

The details of WHESC's workforce planning activities can be found in Exhibit 4 of this application. WHESC's current contract with IBEW for unionized workers expires on March 31, 2026. Costs and models in this application have not been updated to reflect any anticipated new contractual obligations.

1.2.5 Cost of Capital

In this application, WHESC seeks to recover a weighted average cost of capital of 5.66% through rates in the 2025 Test Year, as detailed in Table 1-11. WHESC has prepared this 2025 COS Application in accordance with the Board's guidelines provided in the Report of the OEB on Cost of Capital for Ontario's Regulated Utilities (the "2009 Report") issued on December 11, 2009. For the purposes of preparing this Application, WHESC has used the Cost of Capital Parameters issued by the Board on October 31, 2023 for 2024 Cost of Service applications for short-term debt and return on equity. The long-term debt rate is based on WHESC's existing and Test Year third-party debt, as described in Exhibit 5.

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

Table 1-11: Capital Structure and Cost of Capital

Test Year: 2025

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$25,800,858	3.09%	$797,790
2	Short-term Debt	4.00% (1)	$1,842,918	6.23%	$114,814
3	**Total Debt**	60.0%	$27,643,777	3.30%	$912,604
	Equity				
4	Common Equity	40.00%	$18,429,184	9.21%	$1,697,328
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$18,429,184	9.21%	$1,697,328
7	**Total**	100.0%	$46,072,961	5.66%	$2,609,932

1.2.6 Cost Allocation and Rate Design

1.2.6.1 Cost Allocation

In the March 31, 2011 Cost Allocation Report, the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios to be used in the development of rates. Table 1-12 below provides the Board's acceptable revenue-to-cost ratios, WHESC's revenue-to-cost ratios approved in its 2017 COS, the updated 2025 status quo ratios resulting from the cost allocation study, and the proposed ratios in this application.

The 2025 cost allocation study indicates that the revenue-to-cost ratio for Sentinel Lighting is outside of the Board's policy range at 72.75%. To bring this class within the acceptable range, the Sentinel Lightning class was moved upward to a common revenue-to-cost ratio of 80%. Subsequently, the Residential, Street Lighting and Unmetered Scattered Load classes were adjusted downward by a common ratio, in accordance with Board policy, in order to maintain revenue neutrality.

Table 1-12: Revenue-to-Cost Ratios

Rate Class	2017 Board Approved Ratios	Status Quo Ratios	2025 Proposed Ratios	Policy Range
Residential	104.20%	103.62%	103.62%	85 - 115
General Service < 50	96.40%	87.72%	87.72%	80 - 120
General Service > 50	86.60%	93.54%	93.54%	80 - 120
Sentinel Lights	86.60%	72.75%	80.00%	80 - 120
Street Lighting	120.00%	106.13%	103.62%	80 - 120
Unmetered Scattered Load	120.00%	106.47%	103.62%	80 - 120

The proposals set forth in this Application will change the rates for all rate classes, however no total bill impacts are in excess of 10%. As a result, no mitigations plans are being filed.

WHESC is not proposing to add or remove any rate classes, or any new charges, in this application.

1.2.6.2 Rate Design

In accordance with OEB Board Policy: A New Distribution Rate Design for Residential Electricity Customers, residential rates are fully fixed. WHESC is proposing to maintain the fixed/variable splits from its 2017 COS for Street Lighting, Sentinel Lighting and Unmetered Scattered Load rate classes, as the proposed charge for these rate classes is below the Customer Unit Cost per Month-Minimum System with PLCC Adjustment value. WHESC is proposing to maintain the current 2024 approved fixed charge for the GS<50 and GS>50 rate classes since the proposed Fixed Charge is above the Customer Unit Cost per Month-Minimum System with PLCC Adjustment value.

WHESC's proposed fixed and variable distribution charges are shown in Table 1-13 below.

Table 1-13: Proposed Distribution Charges

Rate Class	Proposed Fixed Distribution Charge	Billing Determinant	Proposed Volumetric Distribution Charge
Residential	32.83	kWh	N/A
GS < 50 kW	36.94	kWh	0.0113
GS > 50 kW	336.30	kW	3.6984
Street Lighting	0.70	kW	2.9684
Sentinel Lighting	5.12	kW	11.4823
Unmetered Scattere	12.14	kWh	0.0080

1.2.7 Deferral and Variance Accounts

As part of this application, WHESC is requesting disposition of its deferral and variances accounts in the total credit amount of $1,224,529.

WHESC is seeking disposition through rate riders over a one-year period effective May 1, 2025. Additional details on WHESC's deferral and variance accounts can be found in Exhibit 9. Table 1-14 below provides a summary of WHESC's total proposed disposition by DVA Account, as well as WHESC's request to continue or cease use of the account.

Table 1-14: DVA Summary by Account

Description	USoA	Principal Balance	Carrying Charge	Total	Continuance
Group 1 Accounts					
Smart Metering Entity Charge Variance Account	1551	- 48,138	- 3,634	- 51,772	Yes
RSVA - Wholesale Market Service Charge	1580	- 439,708	- 48,801	- 488,509	Yes
Variance WMS – Sub-account CBR Class B	1580	58,565	3,922	62,487	Yes
RSVA - Retail Transmission Network Charge	1584	200,500	20,067	220,567	Yes
RSVA - Retail Transmission Connection Charge	1586	153,741	14,413	168,154	Yes
RSVA - Power (excluding Global Adjustment)	1588	- 115,322	- 10,545	- 125,867	Yes
RSVA - Global Adjustment	1589	- 32,813	- 9,021	- 41,834	Yes
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	0	- 13,598	- 13,598	Yes
Total Group 1		**- 223,175**	**- 47,197**	**- 270,372**	
Group 2 Accounts					
Pole Attachment Revenue Variance	1508	- 606,700	- 85,320	- 692,020	Yes
Retail Service Charge Incremental Revenue	1508	- 40,138	- 5,419	- 45,557	Yes
Green Button Initiative Costs	1508	67,826	7,875	75,701	No
Other Regulatory Assets, sub-account OEB Cost Assessment	1508	32,868	7,119	39,987	No
PILs and Tax Variance for 2006 and Subsequent Years- Sub-accoun	1592	- 494,087	- 67,590	- 561,677	No
Meter Cost Deferral Account (MIST Meters)	1557	202,151	27,258	229,409	No
Total Group 2		**- 838,080**	**- 116,077**	**- 954,157**	
Total Proposed Disposition		**- 1,061,255**	**- 163,274**	**- 1,224,529**	

A summary of WHESC's total proposed deferral and variance account disposition, by rate class, is shown in Table 1-15 below.

Table 1-15: Summary of DVA Balances Proposed for Disposition

Rate Class	Group 1	Group 2	MIST Meters Deferral Cost	Total
Residential	- 132,711	- 761,139		- 893,850
General Service < 50	- 33,248	- 146,625		- 179,873
General Service > 50	- 102,505	- 254,519	229,409	- 127,615
Sentinel Lights	- 207	- 2,368		- 2,575
Street Lighting	- 1,299	- 15,846		- 17,145
Unmetered Scattered Load	- 401	- 3,069		- 3,470
Total	- 270,371	- 1,183,566	229,409	- 1,224,528

1.2.8 Bill Impacts

The bill impacts resulting from the proposals within this application are summarized in Table 1-16 below. The bill impacts are based on the commodity rates based on time-of-use and regulatory rates being held constant. Exhibit 8 outlines the calculations used to determine these rate impacts.

Table 1-16: Bill Impacts.

Rate Class	Units	kWh	kW	Subtotal A Distribution exlcluding pass through costs		Subtotal B Distribution		Subtotal C Delivery		Subtotal D Total Bill	
Residential	kWh	750		-$ 2.15	-6.6%	-$ 5.06	-13.1%	-$ 3.98	-7.3%	-$ 3.76	-2.8%
GS < 50 kW	kWh	2,000		-$ 4.80	-8.1%	-$ 12.76	-16.8%	-$ 10.06	-8.9%	-$ 9.49	-2.9%
GS > 50 kW	kW	32,400	60	-$ 3.05	-0.5%	-$ 80.56	-13.2%	-$ 52.04	-5.2%	-$ 80.04	-1.7%
Unmetered Scattered Load	kWh	150		-$ 0.77	-5.7%	-$ 1.36	-9.2%	-$ 1.16	-6.6%	-$ 1.09	-3.3%
Sentinel Lighting	kW	120	0.30	$ 0.31	4.1%	-$ 0.14	-1.6%	-$ 0.01	0.0%	-$ 0.01	0.0%
Street Lighting	kW	16	0.04	-$ 0.13	-15.9%	-$ 0.19	-20.9%	-$ 0.17	-14.7%	-$ 0.19	-5.8%
Residential - 10th Percentile	kWh	260		-$ 2.15	-6.6%	-$ 3.16	-9.1%	-$ 2.79	-6.9%	-$ 2.62	-3.9%

Table 1-17 below provides the bill impacts WHESC proposes to be used in the Notice of Application.

Table 1-17: Bill Impacts - Notice of Application

Rate Class	kWh Usage	Bill Impact	Bill Impact %
Residential	750	-$ 2.15	-6.6%
GS < 50 kW	2000	-$ 4.80	-8.1%

1.3 Administration

1.3.1 Executive Certification

Executive Certification has been provided in Appendix 1-B of this exhibit.

1.3.2 Primary Contact Information

The Applicant:

Welland Hydro-Electric System Corp.
950 East Main St.
Welland, ON L3B 0L9

Primary Application Contact:

Jennifer Dionne
Director of Finance and Regulatory
Phone: (905) 732-1381 Ext. 235
E-Mail: jdionne@wellandhydro.com

1.3.3 Legal Representation

BLG (Borden Lander Gervais LLP)
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Toronto, ON M5H 4E3
Telephone: 416-367-6000
Fax: 416-367-6749

Primary Contact:

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

1.3.4 Internet Address and Social Media

All application materials will be posted on the WHESC website and will also be communicated via WHESC's social media channels as provided below:

Website: www.wellandhydro.com
Facebook: https://www.facebook.com/pages/category/Energy-Company/Welland-Hydro-Electric-System-Corp-371112823000644/

X.com: https://x.com/wellandhydro

1.3.5 Statement of Publication

WHESC will follow the OEB's instructions regarding the Publication of Notice in relation to this Application. The Notice of Application will be published to WHESC's website, under the "Regulatory" and "Media, News & Events" sections:

Regulatory: https://wellandhydro.com/about-us/regulatory/
Media, News, and Events: https://wellandhydro.com/about-us/media/

1.3.6 Material Impacts on Customers

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

1.3.7 Materiality Threshold

WHESC's materiality threshold, as defined in Section 2.0.8 of the Chapter 2 Filing requirements, is defined as 0.5% of the distribution base revenue requirement. WHESC's revenue requirement is greater than $10M and less than $200M.

WHESC's distribution revenue requirement for the 2025 test year in this application is $12,906,586 which results in a calculated materiality threshold of $64,533 as shown in Table 1-18. WHESC has applied the materiality threshold of $64,000 in its analysis through this Application.

Table 1-18: Materiality Threshold Calculation

Description	2025 Test Year
Distribution Base Revenue Requirement	12,906,586
Materiality Threshold	0.5%
Materiality Calculated	64,533
Materiality Used	64,000

1.3.8 Form of Hearing

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

1.3.9 Requested Effective Date of Rate Order

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

1.3.10 Changes to Methodologies used in Previous Application

The methodologies used in this Application are consistent with those applied in WHESC's 2017 COS Application. WHESC has made changes as required by the latest filing requirements used in this Application.

In a letter dated June 12, 2015, the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective Cost of Service ("COS") applications when warranted. In its 2017 COS application (EB-2016-0110), WHESC used the load profiles provided by Hydro One in its cost allocation model. WHESC has updated the load profiles for all rate classes. Load profiles used in this Application were derived utilizing the Historical Average Method, based on actual hourly load by rate class in 2021, 2022 and 2023. Demand allocators for each of these historical years were developed, and subsequently averaged to inform the coincident peak and non-coincident peak inputs for cost allocation purposes.

1.3.11 OEB Directions from Previous Decisions and/or Orders

In the 2017 COS Settlement proposal (EB-2016-0110), WHESC agreed to carry out a full asset condition assessment ("ACA") of its system, and to prepare a new Distribution System Plan ("DSP") that is informed by that ACA.

WHESC conducted an ACA of its system in 2018 to support distribution system planning. WHESC conducted a subsequent ACA in 2023 to appropriately inform the DSP filed in conjunction with this Application. The 2023 ACA can be found in Appendix 5-H of the DSP, filed with Exhibit 2.

1.3.12 Conditions of Service

WHESC's Conditions of Service are posted on its website:

https://wellandhydro.com/wp-content/uploads/2019/09/Conditions-of-Service_revised-March-10-2015_web.pdf

WHESC confirms that this is the current version. WHESC also confirms rates and charges which are the subject of this application are not contained within the Conditions of Service.

1.3.13 Corporate and Distributor Organizational Structure

Welland Hydro-Electric Holding Corp., incorporated under the Business Corporations Act of Ontario, is owned by the sole shareholder, the City of Welland. Welland Hydro-Electric Holding Corp. is the parent holding company of the regulated LDC (WHESC), and an unregulated company Welland Hydro Energy Services Corp.

WHESC is a for-profit, taxable corporation and is a wholly owned subsidiary of Welland Hydro-Electric Holding Corp., under the Ontario's Electricity Act (1998). The OEB has issued Electricity Distribution License ED-2003-0002 (valid until June 19, 2043) to WHESC to provide electrical distribution services to the City of Welland.

Welland Hydro Energy Services Corp. is a wholly owned, unregulated subsidiary of Welland Hydro-Electric Holding Corp. Welland Hydro Energy Services Corp. provides sentinel lightning services; owns and operates FIT solar facilities through a joint-venture with the City of Welland.

The corporate structure is depicted in Table 1-19.

Table 1-19: Corporate Structure

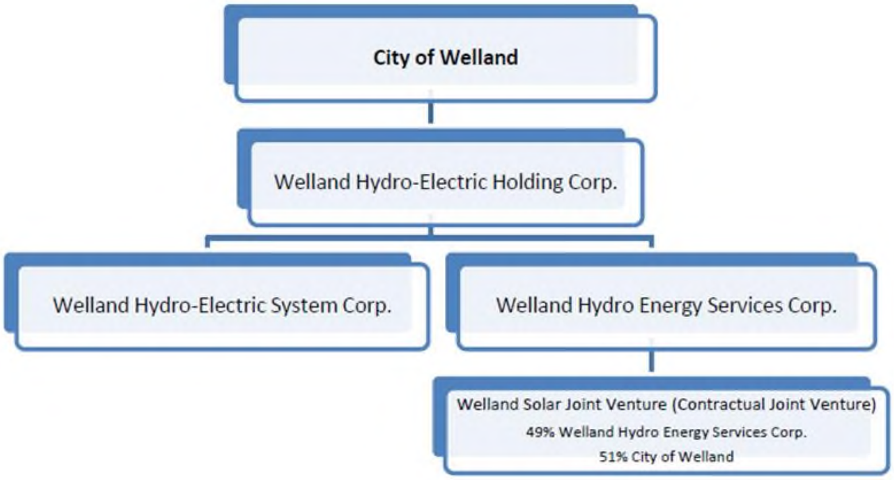
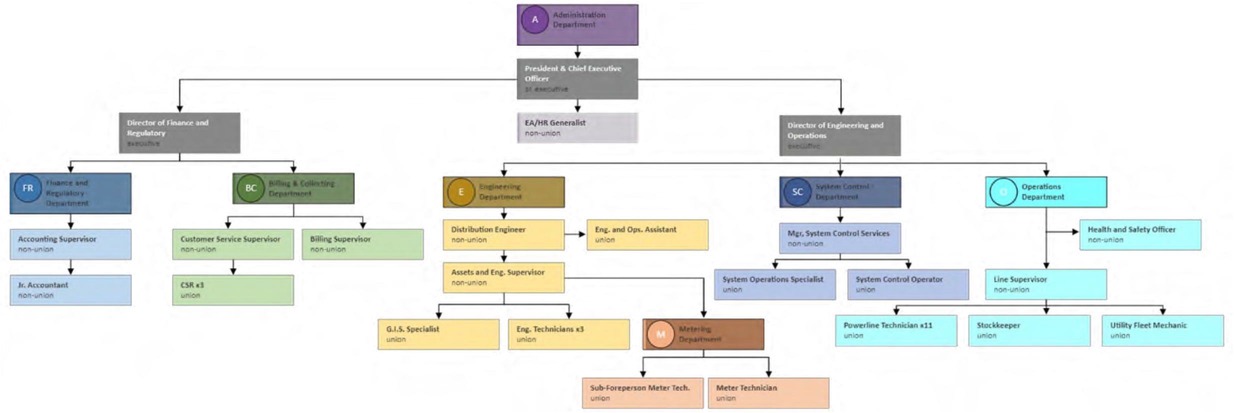


Table 1-20 shown below depicts the organizational structure of WHESC.

Table 1-20: Organizational Structure



1.3.14 List of Specific Approvals Requested

WHESC is seeking the following approvals in this application:

- Approval pursuant to Section 78 of the Ontario Energy Board Act, 1998 to charge distribution rates effective May 1, 2025 to recover a service revenue requirement of $13,845,188 which includes a revenue deficiency of $189,836 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8.
- Approval of the Distribution System Plan as outlined in Exhibit 2 – Appendix 2-E
- Approval to adjust the Retail Transmission Rates – Network and Connection as detailed in Exhibit 8.
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board's Decision and Order in the matter of WHESC's 2024 distribution rates (EB-2023-0056)
- Approval to continue Standard Supply Charge, the Smart Meter Entity Charge and Retail Service Charges as previously approved by the OEB (EB-2023-0056).
- Approval to continue the Specific Service Charges (with the exception of the MicroFIT Monthly Service Charge), Transformer Allowance as previously approved by the OEB and as detailed in Exhibit 8.
- Approval of an updated MicroFIT Monthly Service charge as detailed in Exhibit 8.
- Approval of the proposed loss factors as detailed in Exhibit 8.
- Approval of Deferral and Variance Account disposition amounts as presented in the 2025 DVA Continuity Schedule and Exhibit 9 in the form of rate riders for a one-period.
- Approval to continue obtaining payment from the IESO for Ratepayer Protection under O.Reg 330/09 in the amounts outlined in Exhibit 2.

- The Applicant requests that the OEB make its rate order effective May 1, 2025 in accordance with the Filing Requirements.
- In the event that the OEB is unable to provide a Decision and Rate Order for Implementation by the application as of May 1, 2025, the Applicant requests that the OEB declare its current rates interim, effective May 1, 2025, pending the implementation of the OEB Rate Order for the 2025 rate year.

WHESC may request such other approvals as WHESC may submit and the Board may allow.

1.4 Distribution System Overview

WHESC services electricity customers in the City of Welland as depicted in Table 1-21. The service territory covers 81 square kilometers with 44% classified as rural and 56% as urban.

WHESC owns, maintains, and operates approximately 498 km (circuit kilometers) of overhead primary distribution feeders and 161 km of underground primary distribution circuits. WHESC receives power from a single Transformer Station ("Crowland TS") which is owned and operated by HONI. The station provides nine 27.6kV feeder breakers to distribute power throughout the City via WHESC's 27.6 kV distribution system. WHESC also maintains a 4.16 kV system, supplied by 13 municipal substations.

WHESC's neighbouring LDC's are:

- Canadian Niagara Power Inc.
- Niagara Peninsula Energy Inc.
- Hydro One Networks Inc.

Table 1-21: WHESC's Service Territory

1.4.1 Host vs. Embedded Distributor

There are no embedded LDCs within WHESC's distribution service territory nor is WHESC a host utility to other distributors.

1.4.2 Transmission or High Voltage Assets

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

1.5 Customer Engagement

WHESC routinely engages with its customers to understand how it's performing, the validity of existing strategic objectives, and to identify opportunities to improve service delivery. The RRFE outcomes that tie WHESC's planning process and objectives of this Application have a significant focus on customers' experience and needs. In addition to cyclical engagement activities, WHESC has engaged customers specifically regarding customers' needs and expectations related to WHESC's DSP.

1.5.1 Ongoing Customer Engagement

WHESC's customer base is growing and their demand for real time information is increasing. WHESC has gleaned valuable information from our customers during cyclical surveys where questions were raised regarding the mechanism of communication that is desired. Most of our customers have indicated a desire to have information regarding outages and energy consumption delivered directly through a digital means.

WHESC's Website

WHESC's website remains the primary point of access for customers to find information about the LDC in addition to in-person, telephone, or other online forms of interaction. Links are provided to an outage information landing page, WHESC's social media pages, the online customer facing portal "SilverBlaze", and online forms for requests related to moves, new service requests, etc. WHESC's Green Button portal is also accessible from this website.

WHESC has planned investments in its web-facing deployment in order to improve the customer experience. In alignment with feedback received through ongoing customer engagement as well as engagement conducted in support of this application, WHESC has planned enhancements to its website. WHESC intends to deploy a real time, public facing outage map, driven from its SmartMap system.

WHESC will use its website to post notice of its Application as directed.

Silverblaze Customer Portal

WHESC's customers continue to express their desire to better understand their electricity consumption and rates. WHESC's SilverBlaze portal is available to customers providing the ability to view usage and billing information. Customers can view their monthly, daily, or hourly electricity usage to better manage consumption patterns against rates. Customers can view and download historical bill statements along with usage data for a specific billing period. Customers can also initiate a switch to a different price plan such as from tiered to time-of-use ("TOU") rates. Approximately 5,847 customers have an active profile on the Silverblaze portal.

Live Chat

WHESC has implemented a live chat widget on its website to allow access to a customer service representative online. This allows customers to be provided real time information such as links to online forms and responses to outage inquiries. WHESC has recognized a desire among customers to communicate via online mechanism rather than in person or by telephone. Based on this, WHESC intends to augment its chat capability to provide 24 x 7 access via chatbot functionality. WHESC also intends to augment the existing chat functionality to incorporate real time access to the outage call center on a 24 x 7 basis.

Social Media

WHESC leverages both Facebook and “X” to provide information to customers. Both platforms are monitored to ensure that customer comments or inquiries requiring disposition receive timely follow up. WHESC posts on these two social media platforms on a 24 x 7 basis through its outage call center. Outage updates include posts at the onset of the outage, updates on our dispatch of resources and mitigation, estimated power restoration times, and notice of a power restored condition. While WHESC finds social media to be effective at disseminating outage updates, cyclical customer engagement activities have indicated a preference for direct notification to affected customers. WHESC intends to augment the services provided by its 24 x 7 outage call center to enable digital channels that will permit direct interaction with customers regarding outage updates.

WHESC also leverages social media platforms to provide updates to customers regarding:

- Construction and maintenance activities being conducted
- Information on new programs or offerings
- Safety Messaging
- Rate adjustments
- Employment opportunities

Large Customers

WHESC communicates annually with large commercial customers to discuss power quality, reliability and redundancy issues. Future capacity requirements and any participation in demand response or conservation activities are discussed on an annual basis to assist customers in managing electricity utilization. This also assists WHESC in understanding how utilization changes impact the operation of the distribution system and investment plans.

Municipal Stakeholders

WHESC meets with municipal and regional stakeholders on a weekly basis to review planning and development information. These meetings help inform WHESC on pending distribution system investment requirements and any necessary coordination activities.

Customer Satisfaction Surveys

On a bi-annual basis, WHESC conducts a Customer Satisfaction Survey. The most recent survey was conducted in 2022 by UtilityPULSE. The Customer Satisfaction Survey results assist WHESC in understanding how well it is performing, customer preferences, and areas of focus for improvement.

The bi-annual survey results continue to re-affirm the most important factors to customers in receiving electricity services from WHESC. These are system reliability and affordability. WHESC received an overall customer satisfaction score of 98% benchmarked against the provincial score of 90%. This demonstrates the outcome of WHESC's commitment to managing the two key factors of concern among customers. The latest Customer Satisfaction Survey report is included as Appendix 1-F to this Exhibit.

1.5.2 Application-Specific Customer Engagement

WHESC understands the importance of coordinating investment and expenditure plans with the customers it serves. In support of this Application, WHESC internally designed and implemented a customized customer engagement strategy. The purpose of the engagement was to:

- Educate customers on our role as a distributor
- Provide an understanding of WHESC's cost profile
- Gain information on how customers foresee changes in their electricity usage
- Provide an overview of our investment plan
- Obtain customer feedback regarding the appropriateness of the investment plan
- Confirm preferences for future engagement

WHESC created a survey workbook which can be found in the DSP, Appendix 5-C. The survey was deployed via the internet, using the Constant Contact platform. The platform allowed WHESC to gather survey results in a secure and anonymized manner.

WHESC reached out to 7,459 residential and general service customers that have e-mail contact information on file. The survey was also advertised on WHESC's website and social media platforms. Survey responses were gathered in May of 2024.

There were 988 survey respondents, consisting of 973 residential, 11 GS < 50 kW, and two GS > 50 kW customers. Two respondents completed the survey that are not customers of WHESC. Table 1-22 summarizes the survey responses regarding the type of electricity customer participating.

Table 1-22: Customer Engagement - Type of Electricity Customer

MULTIPLE CHOICE

What type of electricity customer are you?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Residential		973	98%
Small Business (described on your bill as account type GS < 50)		11	1%
Commercial/Industrial (described on your bill as account type GS > 50)		2	0%
I'm not a Welland Hydro customer		2	0%
	Total Responses	988	100%

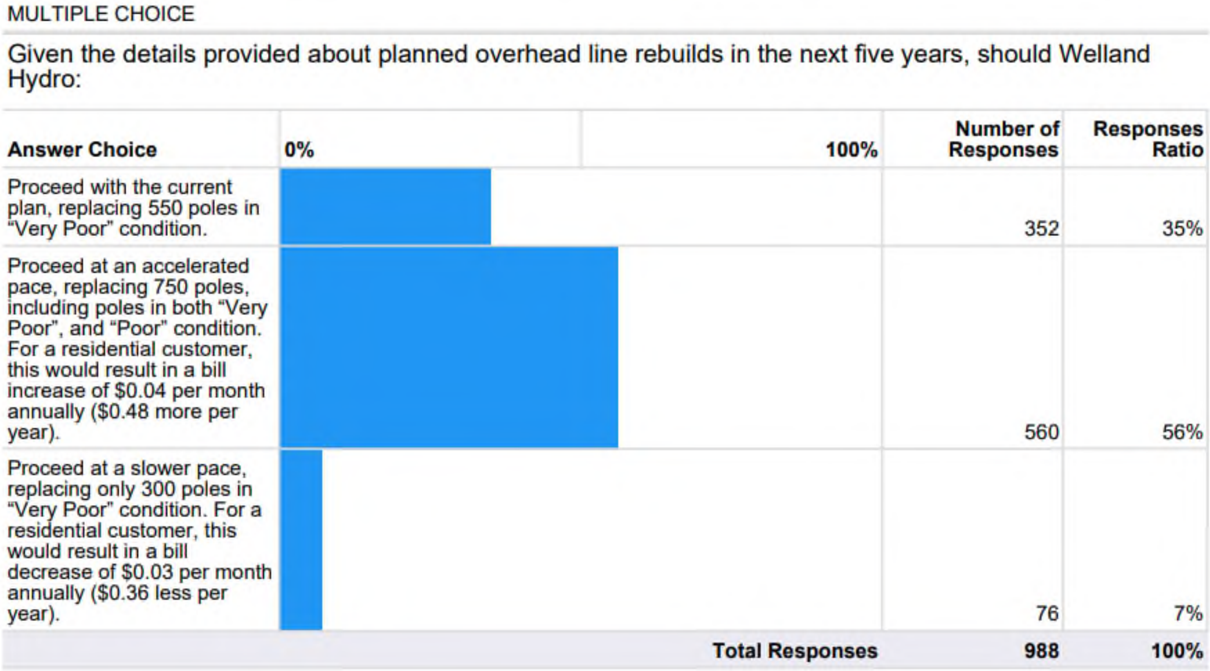
Most respondents indicated that they are satisfied with the service level provided by WHESC. This is in alignment with feedback received from bi-annual customer satisfaction surveys. In addition, as evident in previous surveys, customers indicated that affordability and service reliability are the most important factors for us to consider. WHESC's strategic goals and objectives continue to align with this feedback.

WHESC asked specific questions in support of investment plans in its DSP and the responses are summarized in Exhibit 2, Appendix 2-E. WHESC specifically asked questions to inform investment decisions in the forecast period.

Overhead Line Renewals

Survey participants were given details about planned overhead line rebuilds in the forecast period. Participants were asked whether WHESC should proceed with the proposed plan, replacing 550 poles and associated equipment and conductor in the forecast period, identified in the ACA as being in "Very Poor" condition. Survey respondents were given alternative options of increasing or decreasing the pace of replacing poles in "Very Poor" condition with associated bill impacts. The responses from customers are shown below in Table 1-23. Over 56% of respondents indicated that WHESC should proceed at an accelerated pace. WHESC adjusted it's DSP to increase the amount of overhead system renewal based on this feedback.

Table 1-23: Customer Engagement - Overhead Line Renewal Responses



MULTIPLE CHOICE

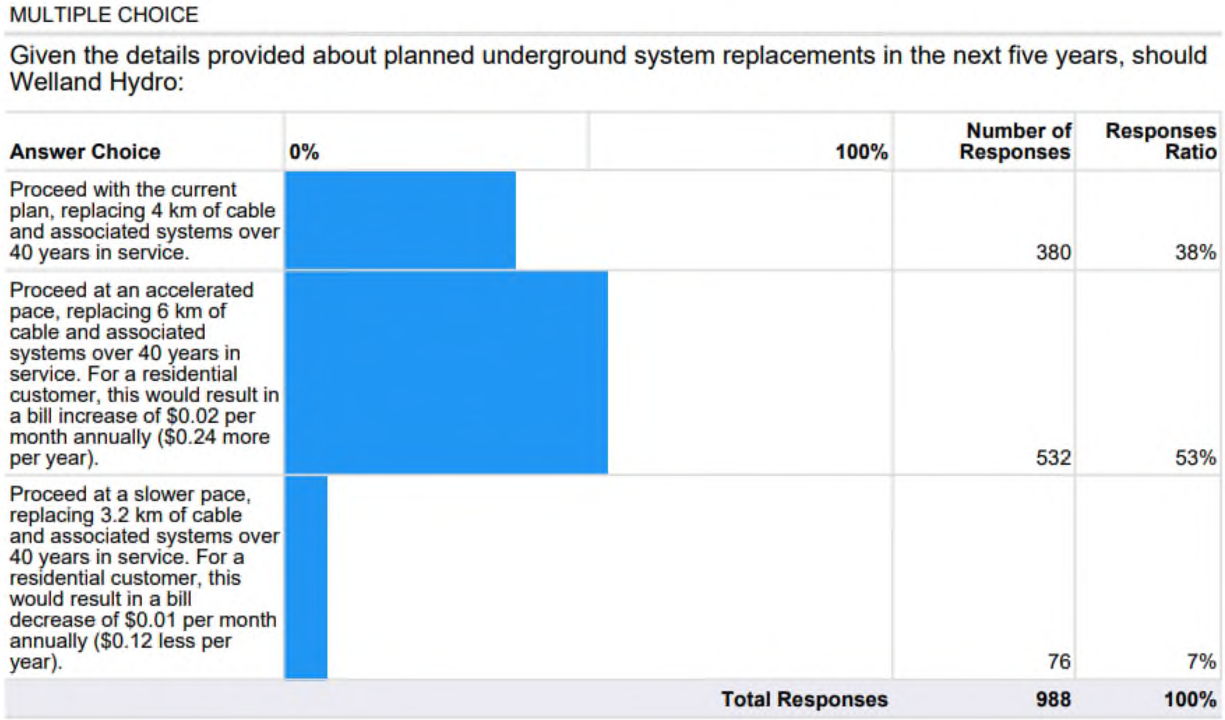
Given the details provided about planned overhead line rebuilds in the next five years, should Welland Hydro:

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 550 poles in "Very Poor" condition.			352	35%
Proceed at an accelerated pace, replacing 750 poles, including poles in both "Very Poor", and "Poor" condition. For a residential customer, this would result in a bill increase of $0.04 per month annually ($0.48 more per year).			560	56%
Proceed at a slower pace, replacing only 300 poles in "Very Poor" condition. For a residential customer, this would result in a bill decrease of $0.03 per month annually ($0.36 less per year).			76	7%
		Total Responses	**988**	**100%**

Underground System Replacements

Survey participants were given details about planned underground system replacements in the forecast period. Participants were asked whether WHESC should proceed with the proposed plan, replacing 4km of cable and associated systems in the forecast period that are over 40 years in-service. Survey respondents were given alternative options of increasing or decreasing the pace of replacing underground systems with over 40 years in-service, along with indication of the associated bill impacts. The responses from customers are shown below in Table 1-24. Over 53% of respondents indicated that WHESC should proceed at an accelerated pace. WHESC adjusted it's DSP to increase the amount of underground system replacements based on this feedback.

Table 1-24: Customer Engagement – Underground System Replacement Responses



MULTIPLE CHOICE

Given the details provided about planned underground system replacements in the next five years, should Welland Hydro:

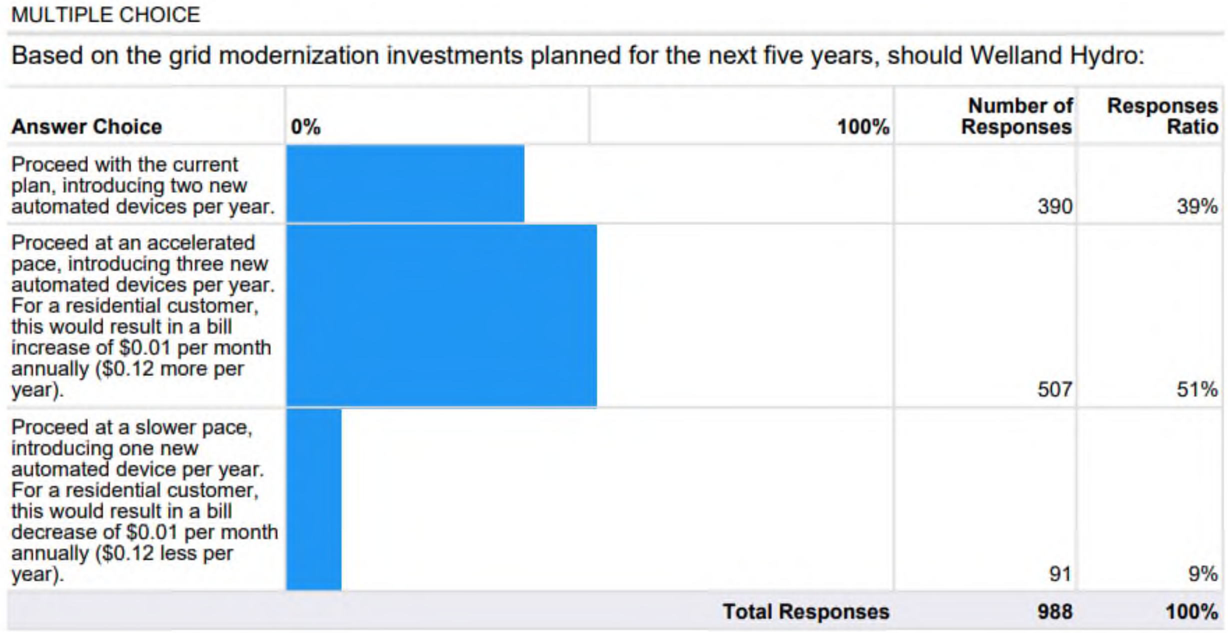
Answer Choice	0%	100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 4 km of cable and associated systems over 40 years in service.			380	38%
Proceed at an accelerated pace, replacing 6 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill increase of $0.02 per month annually ($0.24 more per year).			532	53%
Proceed at a slower pace, replacing 3.2 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).			76	7%
		Total Responses	988	100%

Grid Modernization

Survey participants were given details about planned grid modernization investments. WHESC’s investment plan included the deployment of two automated devices per year in the forecast period. Customers were informed that these devices are designed to detect system anomalies and operate to isolate faulted sections of circuit, minimizing the number of customers impacted by an outage and mitigating the total duration of an outage event.

Participants were asked whether WHESC should proceed with the proposed plan, deploying two automated devices per year in the forecast period. Survey respondents were given alternative options of increasing or decreasing the pace by one unit per year, with indication of the associated bill impacts. The responses from customers are shown below in Table 1-25. Over 51% of respondents indicated that WHESC should proceed with deployment of three automated devices per year in the forecast period. WHESC adjusted it’s DSP to include the deployment of three automated devices based on this feedback.

Table 1-25: Customer Engagement – Underground System Replacement Responses



MULTIPLE CHOICE

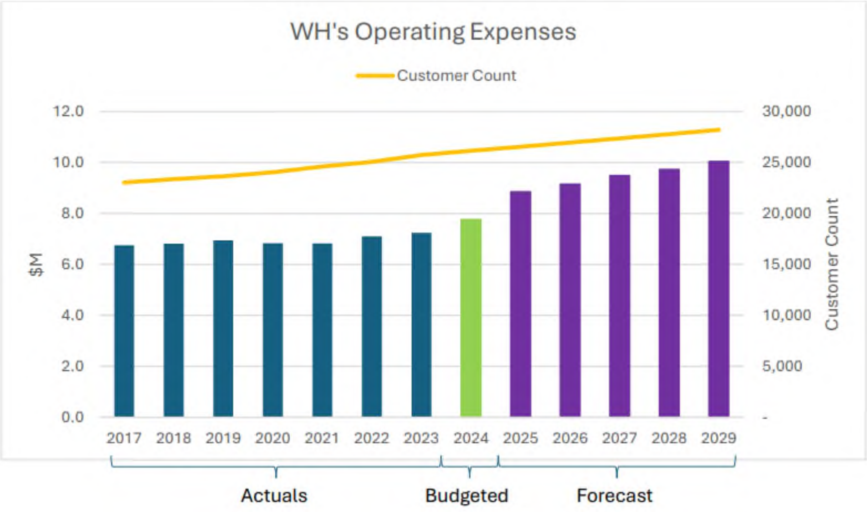
Based on the grid modernization investments planned for the next five years, should Welland Hydro:

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Proceed with the current plan, introducing two new automated devices per year.		390	39%
Proceed at an accelerated pace, introducing three new automated devices per year. For a residential customer, this would result in a bill increase of $0.01 per month annually ($0.12 more per year).		507	51%
Proceed at a slower pace, introducing one new automated device per year. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).		91	9%
	Total Responses	988	100%

Operating Expenses

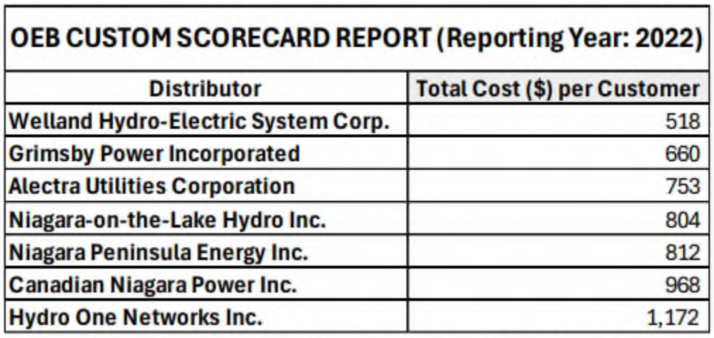
WHESC asked survey participants how appropriate the operating budget is in the forecast period. Survey participants were given indication that the components of WHESC operating expenses are associated with the operation and maintenance of the distribution system as well as the day-to-day administration of IT infrastructure, billing systems, and customer-service related activities. The following chart was presented to survey participants:

Table 1-26: Customer Engagement – Operating Expenses



Survey participants were informed that inflation and customer growth are the two major factors driving WH's forecast operating expenses. Benchmarking results for total cost per customer were provided based on the most recently available data from 2022:

Table 1-27: Customer Engagement – Total Cost ($) per Customer



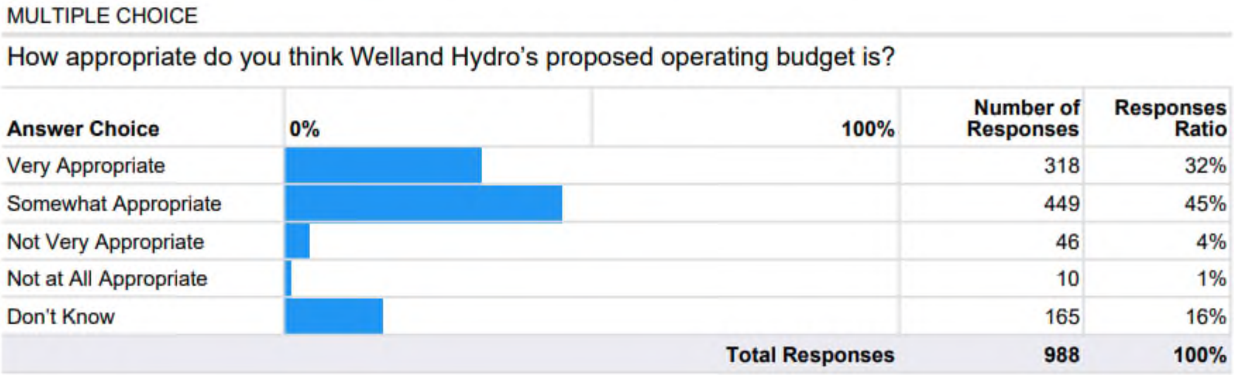
OEB CUSTOM SCORECARD REPORT (Reporting Year: 2022)

Distributor	Total Cost ($) per Customer
Welland Hydro-Electric System Corp.	518
Grimsby Power Incorporated	660
Alectra Utilities Corporation	753
Niagara-on-the-Lake Hydro Inc.	804
Niagara Peninsula Energy Inc.	812
Canadian Niagara Power Inc.	968
Hydro One Networks Inc.	1,172

Source: Electricity Distributor Performance - Build a Custom Report (oeb.ca)

Customers were asked how appropriate WHESC's operating budget is. As shown in Table 1-28, 32% of respondents indicated the proposed operating budget is very appropriate, 45% indicated it was somewhat appropriate. WHESC used this feedback along with responses to questions related to customers service level expectations and preferences to inform finalization of 2025 Test Year budgets.

Table 1-28: Customer Engagement – Proposed Operating Budget



MULTIPLE CHOICE

How appropriate do you think Welland Hydro's proposed operating budget is?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Very Appropriate		318	32%
Somewhat Appropriate		449	45%
Not Very Appropriate		46	4%
Not at All Appropriate		10	1%
Don't Know		165	16%
	Total Responses	988	100%

The balance of the survey questions and majority responses can be summarized as follows:

- Likelihood of Using Electrical Service for:
    - Charing an EV:
      Not Very Likely = 62% (Very Likely ,Likely, Already, total 13%)
    - Connecting Solar Panels:
      Not Very Likely = 67% (Very Likely ,Likely, Already, total 7%)

  - Connecting Battery Storage:
    Not Very Likely = 70% (Very Likely ,Likely, Already, total 7%)

- 69% of respondents indicated that their electricity usage will likely remain the same
- Only 11% of respondents indicated that it was Very Likely or Likely that their primary heating source would be fueled by electricity in the next five years, with 9% indicating it already is.
- 78% of respondents indicated that it is extremely or very important for WHESC to prepare for extreme weather events that may occur in the future, minimizing power outages to the extent possible
- 83% believe access to an online outage map is important
- 61% believe outage communications via social media is important
- 78% believe outage communications via SMS (text message) is important
- 64% believe that improved live chat features to get immediate answers is important
- 77% believe that real time monitoring of consumption for better usage control is important
- 58% believe that expanded customer service department availability in not important given the bill impact
- 60% are likely to complete account changes via online forms
- 77% believe that WHESC's proposed operating budget is very or somewhat appropriate

WHESC utilized the feedback gleaned from this engagement to improve our understanding of customer preferences, outlooks on service utilization, and areas of focus for this cycle of the business plan. WHESC continues to use customer feedback to gauge the validity of strategic objectives and goals.

1.6 Performance Measurement

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

In this application, WHESC has presented its performance for each of the OEB's performance outcomes over the last seven years. This includes discussion on current performance and a projection for continuous improvement over the term of the Application.

1.6.1 Scorecard

On March 15, 2014, the OEB issued its report on Performance Measurement for Electricity Distributors: "*A Scorecard Approach*". The report identifies measures which the OEB expects to use to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes:

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

The OEB has set industry targets for the various metrics in the performance categories that align with these four performance outcomes. WHESC reviews these metrics annually to identify trending and areas that require improvement.

WHESC has published its most recent scorecard on its website at:

https://wellandhydro.com/wp-content/uploads/2023/09/2023-Scorecard-Welland-Hydro-Electric-System-Corp-ENG-FR.pdf

Table 1-29 below summarizes WHESC's performance on scorecard metrics as reported to the OEB in annual RRR filings. WHESC's scorecard including its MD&A for 2022 are provided in Appendix 1-C. The tables that follow in this section show the RRR reported data in 2024 (for the year 2023) along with any relevant commentary related to that year.

Table 1-29: WHESC's Scorecard Performance 2017 to 2023

Performance Outcome	Performance Category	Measures		2017	2018	2019	2020	2021	2022	2023
Customer Focus	Service Quality	New Residential/Small Business Services		100.00%	100.00%	94.82%	94.52%	99.68%	99.61%	95.53%
		Scheduled Appointments Met On Time		98.64%	94.90%	93.16%	98.28%	97.88%	93.99%	94.88%
		Telephone Calls Answered on Time		96.19%	97.29%	88.90%	86.15%	83.07%	77.88%	76.33%
	Customer Satisfaction	First Contact Resolution		75.00%	80.00%	80.00%	77.00%	99.89%	99.81%	99.70%
		Billing Accuracy		99.98%	99.99%	99.99%	99.99%	99.91%	99.88%	99.97%
		Customer Satisfaction Survey Result		92.00%	96.00%	96.00%	96.00%	96.00%	98.00%	98.00%
Operational Effectiveness	Safety	Level of Public Awareness		83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C
		Serious Electrical Incidents	Number of General Public Incidents	1	0	0	0	0	2	0.0
			Rate per 10, 100, 1000 km of Line	0.208	0	0	0	0	0.402	0.0
	System Reliability	SAIDI		1.83	1.46	1.71	2.36	1.52	1.13	1.33
		SAIFI		1.56	1.70	2.41	2.02	1.35	1.14	1.08
	Asset Management	Distribution System Plan Implementation		Completed	Completed	Completed	Completed	Completed	Completed	Completed
	Cost Control	Efficiency Assessment		2	2	2	1	1	1	1
		Total Cost per Customer		$ 497	$ 501	$ 512	$ 494	$ 494	$ 518	$ 561
		Total Cost per km		$ 23,937	$ 24,354	$ 24,714	$ 24,038	$ 24,455	$ 26,144	$ 29,174
Financial Performance	Financial Ratios	Liquidity: Current Ratio		1.51	1.53	1.44	1.73	1.58	1.32	1.41
		Leverage: Total Debt to Equity Ratio		0.81	0.77	0.83	0.97	0.91	0.86	0.92
		Profitability: Regulatory Return on Equity		8.51%	11.41%	10.44%	9.36%	10.72%	11.71%	12.97%

The following subsections summarize WHESC's performance related to the four RRFE outcomes and any related areas of focus for improvement in the period covered by this Application.

1.6.1.1 Customer Focus

A summary of WHESC's performance in metrics related to the Customer Focus RRFE outcome is shown in Table 1-30.

Table 1-30: Customer Focus Outcomes

Performance Outcome	Performance Category	Measures	2017	2018	2019	2020	2021	2022	2023
Customer Focus	Service Quality	New Residential/Small Business Services	100.00%	100.00%	94.82%	94.52%	99.68%	99.61%	95.53%
		Scheduled Appointments Met On Time	98.64%	94.90%	93.16%	98.28%	97.88%	93.99%	94.88%
		Telephone Calls Answered on Time	96.19%	97.29%	88.90%	86.15%	83.07%	77.88%	76.33%
	Customer Satisfaction	First Contact Resolution	75.00%	80.00%	80.00%	77.00%	99.89%	99.81%	99.70%
		Billing Accuracy	99.98%	99.99%	99.99%	99.99%	99.91%	99.88%	99.97%
		Customer Satisfaction Survey Result	92.00%	96.00%	96.00%	96.00%	96.00%	98.00%	98.00%

Service Quality

WHESC follows the specified OEB targets for service quality-based metrics. In the period from 2017 to 2023, WHESC has exceeded the OEB target of 90% for new residential and small business services connected within five business days or less. WHESC uses a software-based tracking tool for new services that manages pre-requisites for a new connection to proceed. Operations staff leverage this tool to ensure that new service connections are expedited once all pre-requisites are met.

WHESC also tracks whether scheduled appointments are met on time through its work force management software. WHESC has exceeded the OEB target of 90% for this measure in each year of the historical period.

Additionally, WHESC's telephone system tracks the time elapsed before staff answer inbound calls in queue. WHESC's performance against the "Telephone Calls Answered on Time" measure has declined over the historical period. Although still exceeding the OEB target of 65% or greater, WHESC attributes the decline in performance to growth and associated workload demand for new/upgrade service processing through the customer service department. WHESC has identified resource adjustments in the COS filing associated with this Application, with the intention of addressing declining performance.

Customer Satisfaction

WHESC has improved its performance over the historical period, resolving a customer's inquiry on first contact over 99% of the time since 2021. Billing accuracy continues to remain well above the OEB defined target of 98%. For this metric, WHESC uses an internal target of 99.5%.

WHESC conducts bi-annual customer satisfaction surveys to determine how the LDC is performing against both provincial and national peers. The latest survey was conducted in 2022 and 98% of customers indicated they are satisfied with the overall service level provided by WHESC. The survey helps inform WHESC's future investment planning. Customers continue to indicate that affordability and service reliability are the most important considerations related to WHESC's service.

1.6.1.2 Operational Effectiveness

A summary of WHESC's performance in metrics related to the Operational Effectiveness RRFE outcome is shown in Table 1-31.

Table 1-31: Operational Effectiveness Outcomes

Performance Outcome	Performance Category	Measures		2017	2018	2019	2020	2021	2022	2023
Operational Effectiveness	**Safety**	Level of Public Awareness		83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C
		Serious Electrical Incidents	Number of General Public Incidents	1	0	0	0	0	2	0.0
			Rate per 10, 100, 1000 km of Line	0.208	0	0	0	0	0.402	0.0
	System Reliability	SAIDI		1.83	1.46	1.71	2.36	1.52	1.13	1.33
		SAIFI		1.56	1.70	2.41	2.02	1.35	1.14	1.08
	Asset Management	Distribution System Plan Implementation		Completed	Completed	Completed	Completed	Completed	Completed	Completed
	Cost Control	Efficiency Assessment		2	2	2	1	1	1	1
		Total Cost per Customer		$ 497	$ 501	$ 512	$ 494	$ 494	$ 518	$ 561
		Total Cost per km		$ 23,937	$ 24,354	$ 24,714	$ 24,038	$ 24,455	$ 26,144	$ 29,174

Safety

WHESC has met or exceeded the OEB defined metrics related to the safety of employees and the public, throughout the historical period. WHESC conducts bi-annual electrical safety awareness surveys to confirm the public's understanding of electrical hazards related to our distribution system.

WHESC continues to maintain full compliance with Ontario Regulation 22/04. Maintenance, operation, and implementation of new distribution system plant adheres to Electrical Safety Authority ("ESA") guidelines based on annual third party audit findings.

A requirement of Ontario Regulation 22/04 is the reporting of serious electrical incidents. Generally, any time a portion of the electrical system operating over 750 V interacts with the public space, the incident is reportable with a few exceptions. For 2017, WHESC reported one serious electrical incident. Following a fault on WHESC's 4.16 kV system, a restricted conductor failed and entered the public space in an energized condition.

In 2022, WHESC reported two serious electrical incidents. One was attributed to a member of the public vandalizing a 4.16kV distribution pole, causing primary conductor to enter the public space. The second was due to failure of a primary connector on the 4.16kV system, causing a primary conductor to enter the public space.

These events did not result in injury to a member of the public or WHESC staff. The incidents along with those not meeting ESA's reporting criteria are reviewed at Operations Committee meetings. Negative trends are identified along with opportunities for corrective action. In addition to taking steps to increase electrical safety awareness to the public within our service area, WHESC has incorporated mitigation of known safety risks into its capital investment plans. There are several system renewal projects identified in the DSP that incorporate the removal of hazardous and deteriorated conductor from the distribution system.

System Reliability

WHESC monitors system reliability indices System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") on a monthly basis. The indices and associated trends are reviewed in recurring, board-level Operations Committee meetings.

WHESC has experienced a decrease in the average number of hours that a customer is interrupted annually from 1.95 in 2017 to 1.50 in 2023. This is depicted in Table 1-32 and shown as SAIDI (ALL). WHESC attributes the decrease in SAIDI to two main factors. First, WHESC has invested in SCADA based technology and protection system enhancements that improve grid visibility. These investments allow

WHESC to reduce the number of customers exposed to an outage event down to a small section of a circuit through either automated protection operations or remote switching. Second, WHESC has deployed a 24 x 7 control room operation, allowing these technology enhancements to be utilized at all times.

Table 1-32: Annual SAIDI from 2017 to 2023

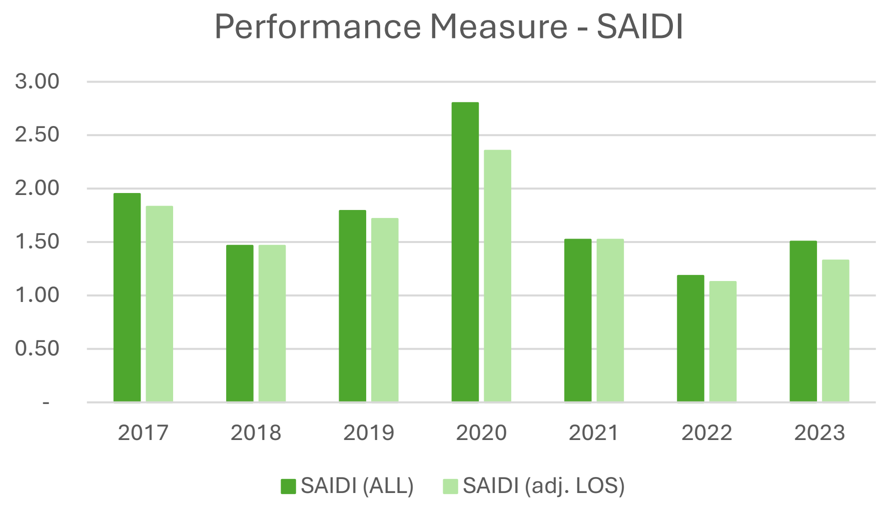
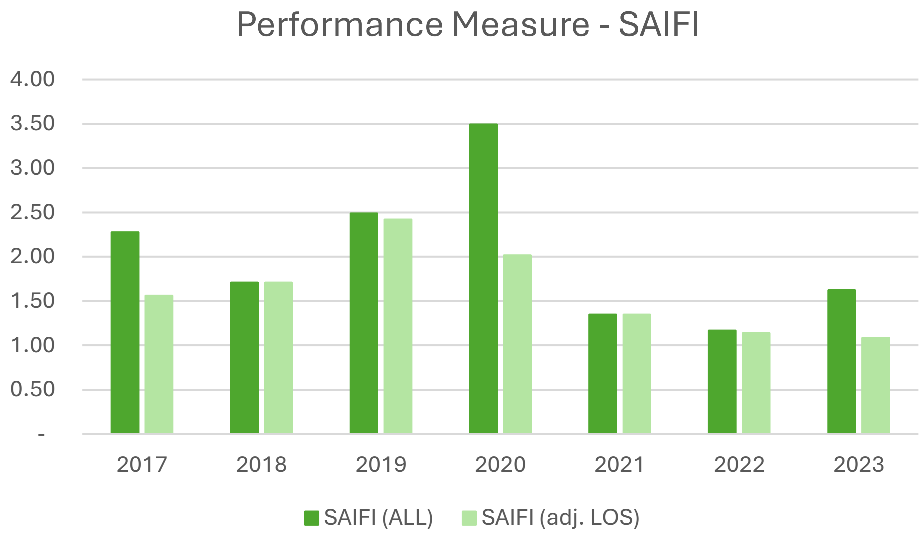


Table 1-33 depicts the trend in the frequency that customers are interrupted on an annual basis. This is shown as SAIFI (ALL).

Table 1-33: Annual SAIFI from 2017 to 2023



The frequency of outages experienced by WHESC customers has decreased from 2.28 in 2017 to 1.61 in 2023. This is attributed to the same reasons identified above that are contributing to the decline in SAIDI. Protection system operations limit the portion of distribution system exposed to a system anomaly, reducing the number of sustained outages experienced by customers. As detailed in WHESC'S DSP in Exhibit 2, Appendix 2-A, SAIFI in the historical period was influenced by loss of supply events. This highlights the need for investments identified in the most recent Integrated Regional Resource Plan ("IRRP") report issued by the IESO. WHESC is supplied from Crowland TS which is beyond its Typical Useful Life ("TUL") and over capacity.

WHESC monitors system reliability performance as a key input to its investment planning process. As WHESC's system expands to accommodate additional customers and load growth, there must be strategies to maintain system reliability overall for customers. Expansion of the distribution system leads to increased exposure and WHESC has identified investments that mitigate this through the continued expenditure on grid modernization.

Asset Management

WHESC's last DSP covered the period 2017 through 2021. WHESC tracked DSP progress through Operations Committee review of annual variances. Throughout the period, WHESC generally met or exceeded planned expenditures. The 2018 Asset Condition Assessment ("ACA") report provided valuable insight into the annual capital planning process, influencing internally driven expenditures and system renewal pacing to sustain asset health.

The DSP outlines the forecasted capital expenditures over the next five year period. These have been informed by inputs to the planning process as described in the DSP, including an updated ACA report produced in 2023. In the forecast period, WHESC will continue to measure the progress of its DSP implementation as a ratio of total actual capital expenditures over the total amount of planned capital expenditure in the specific forecast year.

Cost Control

The total cost for Ontario LDCs is evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The PEG econometric model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of line, etc. Efficiency is determined by using a model that compares actual total cost to predicted total cost. A three year average of where an LDC is performing in comparison to predicted total cost determines the efficiency ranking.

The efficiency rankings result in a Cohort assignment as follows:

- Cohort 1: Actual costs are more than 25% below predicted costs
- Cohort 2: Actual costs are between 10% and 25% below predicted costs
- Cohort 3: Actual costs are within 10% of predicted costs
- Cohort 4: Actual costs are between 10% and 25% above predicted costs
- Cohort 5: Actual costs are more than 25% above predicted costs

As shown in Table 1-31, WHESC moved to Cohort 1 in 2020 based on Pacific Energy Group's benchmarking and efficiency assessment in that year, observing the prior three year average. Cost per customer has remained stable through the historical period, below the pace of inflation and growth.

WHESC maintains the objective of remaining in Cohort 1 throughout the period of the current business plan cycle. WHESC has evaluated its performance in the 2025 Test Year and confirms that the three year average performance is such that actual costs are more than 25% below predicted costs. This result is shown in Table 1-34.

Table 1-34: Cost Benchmarking Results

Summary of Cost Benchmarking Results

Welland Hydro-Electric System Corp.

	2020 (History)	2021 (History)	2022 (History)	2023 (History)	2024 (Bridge)	2025 (Test Year)
Cost Benchmarking Summary						
Actual Total Cost	11,874,844	12,154,000	12,993,461	14,445,324	15,755,141	17,198,605
Predicted Total Cost	16,082,567	16,836,832	18,568,263	21,309,905	22,430,601	24,337,040
Difference	(4,207,723)	(4,682,832)	(5,574,802)	(6,864,581)	(6,675,460)	(7,138,435)
Percentage Difference (Cost Performance)	**-30.3%**	**-32.6%**	**-35.7%**	**-38.88%**	**-35.33%**	**-34.72%**
Three-Year Average Performance			-32.9%	-35.72%	-36.64%	-36.31%
Stretch Factor Cohort						
Annual Result	1	1	1	1	1	1
Three Year Average			1	1	1	1

WHESC's stability in Cohort 1 is a testament to the prudence of management's capital and operating expenditure decisions. WHESC will continue to pursue efficiencies through headcount management with a focus on core business functions and continuing to explore opportunities to address business requirements with shared services concepts.

WHESC's Total Cost per Customer is calculated as the sum of capital and operating costs, divided by the total number of customers served. WHESC's total cost per customer in 2023 increased only 12.8% since 2017, well below the influences of inflation and growth over the period.

Benchmarking WHESC's total cost per customer for the period 2018 to 2022 (latest year of data available at the time of this writing), WHESC is the lowest of LDC's in the Niagara Region. This is shown in Table 1-35.

Table 1-35: Benchmarking Total Cost per Customer

LDC	Total Cost per Customer ($)				
	2018	2019	2020	2021	2022
Welland Hydro-Electric System Corp.	501	512	494	494	518
Grimsby Power Incorporated	584	594	598	602	660
Alectra Utilities Corporation	681	716	686	691	753
Niagara-on-the-Lake Hydro Inc.	761	758	750	768	804
Niagara Peninsula Energy Inc.	755	786	758	750	812
Canadian Niagara Power Inc.	867	893	868	905	968
Hydro One Networks Inc.	1,017	1,044	1,018	1,033	1,172

WHESC's Total Cost per km is calculated as the sum of capital and operating costs, divided by the total circuit kilometers of line. WHESC's total cost per km in 2023 increased 21.9% since 2017. One factor in the trend for this metric is the impact of WHESC's rebuild and voltage conversion efforts on the total circuit kilometers of line. In some cases, a rebuild/conversion project results in the elimination of circuit(s), placing downward pressure on total circuit kilometers.

Table 1-36 shows WHESC benchmarked against regional LDC's for total cost per km of line. While WHESC has the highest cost per km of line in the region, the table suggests a direct correlation between both the customer density and customers per circuit length in kilometers. WHESC supplies approximately 50 customers per circuit km of line (in 2022) which is the highest density in the region. The next highest density in the region is Niagara-on-the-Lake Hydro at 30 customers per circuit km of line. The table suggests density is a factor in this metric given a correlation between cost per km and customers served per km of line.

Table 1-36: Benchmarking Total Cost per km of Line

LDC	Total Cost per km ($)					Customer Count	Service Area	Circuit kms	Customer Density (#/sq. km)	Customer per km of Line
	2018	2019	2020	2021	2022	2022				
Alectra Utilities Corporation	33,860	15,212	14,730	14,252	15,952	1,076,537	1,923	50,795	560	21
Canadian Niagara Power Inc.	24,425	16,421	16,581	17,810	19,189	30,433	357	1,535	85	20
Grimsby Power Incorporated	9,793	10,029	10,121	10,315	11,287	11,870	69	694	172	17
Hydro One Networks Inc.	11,364	11,761	11,571	11,940	13,537	1,440,085	961,142	124,741	1	12
Niagara Peninsula Energy Inc.	20,745	13,712	13,139	9,522	10,327	58,222	827	4,578	70	13
Niagara-on-the-Lake Hydro Inc.	19,565	19,676	19,566	23,000	24,066	9,816	133	328	74	30
Welland Hydro-Electric System Corp.	24,354	24,714	24,038	24,455	26,144	25,063	81	497	309	50

1.6.1.3 Public Policy Responsiveness

Connection of Renewable Generation

Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within the prescribed timelines documented in the OEB's Distributed Energy Resources ("DER") connection procedures. Distributors are also required to connect micro-embedded generation facilities within five business days of receiving all required authorizations, signed agreements, and connection fees. WHESC has met these requirements consistently from 2017 to 2023.

WHESC's target for these metrics in 2024 moving forward is to complete assessments and generation facility connections within the prescribed timelines of the applicable connection procedures.

1.6.1.4 Financial Performance

A summary of WHESC's performance in metrics related to the Financial Performance RRFE outcome is shown in Table 1-37.

Table 1-37: Operational Effectiveness Outcomes

Performance Outcome	Performance Category	Measures	2017	2018	2019	2020	2021	2022	2023
Financial Performance	**Financial Ratios**	Liquidity: Current Ratio	1.51	1.53	1.44	1.73	1.58	1.32	1.41
		Leverage: Total Debt to Equity Ratio	0.81	0.77	0.83	0.97	0.91	0.86	0.92
		Profitability: Regulatory Return on Equity	8.51%	11.41%	10.44%	9.36%	10.72%	11.71%	12.97%

Financial Ratios

The three key performance categories related to the "Financial Performance" outcomes are "Liquidity", "Leverage", and "Profitability" are shown in the table above for the period 2017 to 2023.

As an indicator of financial health is a liquidity ratio (current assets / current liabilities) greater than 1.0. This indicates that WHESC can pay its short term debts and meet financial obligations. WHESC has consistently maintained a liquidity ratio above 1.0.

The OEB has set a deemed capital structure of 60% debt and 40% equity for LDCs operating in Ontario. This deemed structure assumes a debt-to-equity ratio of 1.5 (60/40). A debt-to-equity ratio greater than 1.5 indicates that a distributor is more leveraged than the deemed capital structure. WHESC has consistently operated with a debt-to-equity ratio below 1.0 in the historical period. This demonstrates that WHESC is able to leverage additional debt should this be required to fund capital investment. WHESC has identified the need for debt to fund capital investment in the business plan associated with this Application.

WHESC's deemed regulatory return from the 2017 COS was 8.78%. The OEB allows a distributor to earn within +/-3% of the expected Return on Equity (ROE). In 2023, WHESC exceeded the +3% deadband due to stronger than normal growth and unanticipated FTE losses. Prior to 2023, WHESC's achieved ROE was within the +/-3% deadband. WHESC views the conditions experienced in 2023 to be anomalous in relation to growth projections and temporary FTE count reduction. WHESC continues to rely on load projections established in support of the 2022 IRRP, subsequent RIP, and this Application as the basis for growth in the forecast period.

1.6.2 Activity and Program-based Benchmarking

On February 25, 2022, the Ontario Energy Board (OEB) announced changes to the Activity and Program-based Benchmarking (APB) framework to help drive utility performance and support efficiencies in the regulatory process. LDCs were asked to submit data for the period 2018 through 2020 for the 10 APB programs used to benchmark areas of O&M and Capital cost. WHESC submitted this historical data as requested.

WHESC has performed an analysis of APB results against the six other LDCs supplying electricity to customers in the Niagara Region. This is inline with the analysis related to total cost benchmarking supplied above. The subsections below contain a discussion of WHESC's unit costs regionally and against the industry average in each applicable program. The analysis is based on the currently available dataset which contains data up to and including 2022.

1.6.2.1 Billing O&M

WHESC's unit cost for Billing O&M averaged $38.99 per customer between 2018 and 2022. This average places WHESC sixth in the region and is $5.67 per customer higher than the regional average. In analyzing the data below, WHESC's unit cost per customer has decreased from 2018 levels. WHESC has taken steps to significantly reduce the headcount in the Billing & Collecting department, as evidenced in Exhibit 4, Section 4.3.1.4, in order to manage ongoing cost pressures. WHESC migrated to third-party bill processing in 2023. WHESC will continue to monitor its benchmarked performance against industry cohorts for cost competitiveness.

Table 1-38: Billing O&M per Customer Benchmarking

Distributor	Billing O&M - Unit Cost per Customer ($)					
	2018	2019	2020	2021	2022	Average
Canadian Niagara Power Inc.	$ 16.20	$ 14.37	$ 13.25	$ 12.68	$ 11.82	$ 13.66
Alectra Utilities Corporation	$ 13.32	$ 30.63	$ 27.20	$ 27.64	$ 29.97	$ 25.75
Hydro One Networks Inc.	$ 34.14	$ 30.12	$ 31.80	$ 30.51	$ 29.97	$ 31.31
Niagara-on-the-Lake Hydro Inc.	$ 33.84	$ 29.97	$ 37.43	$ 38.35	$ 42.95	$ 36.51
Grimsby Power Incorporated	$ 39.76	$ 36.40	$ 36.06	$ 34.96	$ 36.07	$ 36.65
Welland Hydro-Electric System Corp.	$ 39.51	$ 38.05	$ 38.03	$ 40.08	$ 39.26	$ 38.99
Niagara Peninsula Energy Inc.	$ 52.67	$ 52.25	$ 48.52	$ 47.58	$ 50.91	$ 50.39
Regional Average						$ 33.32
Industry Average						$ 26.43

1.6.2.2 Metering O&M

WHESC's unit cost for Metering O&M ranks 2nd regionally and is $5.09 per customer below the regional average. WHESC has reduced its headcount in the Meter Department since the 2017 COS which contributes to the management of total O&M cost in this department. WHESC's Metering O&M cost is below the Industry Average as shown in Table 1-39.

Table 1-39: Metering O&M per Customer Benchmarking

Distributor	Metering O&M - Unit Cost per Customer ($)					
	2018	2019	2020	2021	2022	Average
Alectra Utilities Corporation	$ 14.96	$ 8.58	$ 3.37	$ 4.24	$ 3.55	$ 6.94
Welland Hydro-Electric System Corp.	$ 11.68	$ 12.31	$ 13.56	$ 16.22	$ 16.42	$ 14.04
Niagara Peninsula Energy Inc.	$ 17.80	$ 17.55	$ 19.71	$ 21.12	$ 20.49	$ 19.34
Niagara-on-the-Lake Hydro Inc.	$ 20.07	$ 19.17	$ 19.86	$ 20.90	$ 18.56	$ 19.71
Hydro One Networks Inc.	$ 23.14	$ 21.09	$ 19.34	$ 19.19	$ 21.18	$ 20.79
Grimsby Power Incorporated	$ 26.26	$ 19.81	$ 24.75	$ 26.55	$ 28.32	$ 25.14
Canadian Niagara Power Inc.	$ 27.29	$ 29.43	$ 27.05	$ 28.29	$ 27.65	$ 27.94
Regional Average						$ 19.13
Industry Average						$ 13.96

1.6.2.3 Vegetation Management O&M

WHESC's unit cost for vegetation management on a per pole basis averaged $28.15 in the period from 2018 to 2022. This unit cost is $4.51 below the regional average and $39.51 below the industry average. Hydro One is viewed as an outlier given differences in the provincial demographic related to vegetation management requirements. With Hydro One removed from the regional cohort, the average unit cost is $25.59. WHESC is performing vegetation management with unit costs $2.56 above this adjusted average, ranking 5th regionally. While WHESC has taken steps to manage third-party service provider costs over this period, one of the factors that contributes to vegetation management costs is the significance of rear-lot primary distribution. Managing vegetation in rear-lot scenarios adds significant cost due to the requirement for specialized equipment and labour based on restricted access. WHESC has included a significant component of rear-lot voltage conversion in its DSP, leading to the reduction of rear-lot installed primary. This will place downward pressure on vegetation management costs over time.

Table 1-40: Vegetation O&M per Pole Benchmarking

Distributor	Vegetation O&M - Unit Cost per Pole ($)					
		2019	2020	2021	2022	Average
Niagara-on-the-Lake Hydro Inc.	$ 15.67	$ 15.96	$ 10.33	$ 12.27	$ 14.01	$ 13.65
Niagara Peninsula Energy Inc.	$ 13.98	$ 14.95	$ 13.80	$ 18.54	$ 14.69	$ 15.19
Grimsby Power Incorporated	$ 16.54	$ 24.79	$ 19.41	$ 30.02	$ 20.43	$ 22.24
Canadian Niagara Power Inc.	$ 19.55	$ 21.69	$ 24.79	$ 25.66	$ 26.06	$ 23.55
Welland Hydro-Electric System Corp.	$ 26.30	$ 31.49	$ 26.98	$ 24.25	$ 31.75	$ 28.15
Alectra Utilities Corporation	$ 43.43	$ 40.71	$ 38.03	$ 36.42	$ 35.43	$ 38.80
Hydro One Networks Inc.	$ 82.35	$ 97.08	$ 82.24	$ 86.76	$ 86.90	$ 87.07
Regional Average						$ 32.66
Industry Average						$ 67.76

1.6.2.4 Lines O&M

WHESC ranks seventh regionally and is well above the regional and industry average unit cost for Lines O&M. WHESC's unit costs are $3658.88 per km or $74.33 per customer as shown in the tables below. This program and its associated USoA's include WHESC's engineering, stores, and fleet costs that are not directly allocated to capital or billable work orders. This is an area where WHESC believes that it likely includes more costs than other LDCs, particularly since WHESC's total cost per customer benchmarking places it first regionally. Due to the results of benchmarking in this program, WHESC plans to investigate the cost components within this group to ensure that it is allocating costs consistently with other LDCs and will make appropriate adjustments on a go forward basis.

Table 1-41: Lines O&M per Circuit km Benchmarking

Distributor	Lines O&M - Unit Cost per Circuit km ($)				
	2019	2020	2021	2022	Average
Hydro One Networks Inc.	$ 556.25	$ 567.01	$ 561.94	$ 539.38	$ 556.14
Niagara Peninsula Energy Inc.	$ 1,275.13	$ 1,316.92	$ 882.40	$ 1,122.79	$ 1,149.31
Grimsby Power Incorporated	$ 1,115.79	$ 1,277.70	$ 1,269.19	$ 1,253.78	$ 1,229.12
Niagara-on-the-Lake Hydro Inc.	$ 1,272.52	$ 1,128.16	$ 1,424.86	$ 1,367.86	$ 1,298.35
Canadian Niagara Power Inc.	$ 1,132.36	$ 1,368.87	$ 1,310.54	$ 1,419.54	$ 1,307.83
Alectra Utilities Corporation	$ 2,284.86	$ 2,271.54	$ 2,264.25	$ 2,844.91	$ 2,416.39
Welland Hydro-Electric System Corp.	$ 3,922.15	$ 3,450.41	$ 3,452.54	$ 3,810.44	$ 3,658.88
Regional Average					$ 1,659.43
Industry Average					$ 1,042.10

Table 1-42: Lines O&M per Customer Benchmarking

Distributor	Lines O&M - Unit Cost per Customer ($)				
	2019	2020	2021	2022	Average
Alectra Utilities Corporation	$ 45.74	$ 45.28	$ 45.68	$ 57.30	$ 48.50
Canadian Niagara Power Inc.	$ 39.90	$ 47.67	$ 44.02	$ 47.20	$ 44.70
Grimsby Power Incorporated	$ 24.08	$ 27.55	$ 26.94	$ 26.72	$ 26.32
Hydro One Networks Inc.	$ 49.44	$ 49.91	$ 49.14	$ 46.71	$ 48.80
Niagara Peninsula Energy Inc.	$ 46.42	$ 47.87	$ 31.28	$ 39.67	$ 41.31
Niagara-on-the-Lake Hydro Inc.	$ 48.99	$ 43.22	$ 47.59	$ 45.71	$ 46.38
Welland Hydro-Electric System Corp.	$ 81.21	$ 70.86	$ 69.68	$ 75.56	$ 74.33
Regional Average					$ 47.19
Industry Average					$ 39.60

1.6.2.5 Stations O&M

This program includes operating and maintenance costs for distribution substations. Of the seven regional LDCs in the Cohort, only five have distribution class substations. The remaining two LDCs were removed from the table below.

This metric is calculated by taking the total station O&M cost, divided by the total MVA of power transformer capacity installed. WHESC has 13 substations in operation with an average rating of approximately 5.5 MVA. In 2022, WHESC had a total cost of approximately $177,000 to operate and maintain the fleet of 13 substations.

WHESC has replaced the majority of its power transformers in substations, reducing the nameplate capacity to match reduced demand on the 4.16kV system. This drives the benchmarked unit costs up. The O&M per station remained consistent through the period with costs inclusive of station service, snow removal, insurance, property taxes, communications, contract services, salaries, and vehicles. WHESC expects reduced communications expenditure moving forward as it migrates systems from legacy leased circuits to wireless at reduced monthly costs. Voltage conversions identified in the DSP will continue to lessen the capacity requirements of distribution substations over time.

Table 1-43: Station O&M per MVA Benchmarking

Distributor	Station O&M - Unit Cost per MVA ($)					
	2018	2019	2020	2021	2022	Average
Niagara Peninsula Energy Inc.	$ 237.41	$ 138.99	$ 334.93	$ 844.79	$ 570.09	$ 425.24
Canadian Niagara Power Inc.	$ 814.39	$ 637.16	$ 672.27	$ 527.55	$ 372.30	$ 604.73
Alectra Utilities Corporation	$ 645.85	$ 1,205.63	$ 1,015.76	$ 1,194.32	$ 1,371.51	$ 1,086.61
Hydro One Networks Inc.	$ 1,864.71	$ 1,878.56	$ 2,029.97	$ 1,957.18	$ 1,949.83	$ 1,936.05
Welland Hydro-Electric System Corp.	$ 2,944.53	$ 3,337.69	$ 2,882.48	$ 2,527.64	$ 2,457.23	$ 2,829.91
Regional Average						$ 1,376.51
Industry Average						$ 1,399.00

1.6.2.6 Poles, Towers O&M

WHESC ranks sixth in the regional Cohort with O&M costs per pole $7.17 above the industry average. WHESC has experienced a declining trend in the historical period and expects costs to remain in line with inflation in future years. Major cost components in this program are pole testing, disposal costs, salaries, and vehicle usage.

It does appear that there are some inconsistencies in the costs being recorded to USoA 5120 when observing cost trends among LDCs in this cohort.

Table 1-44: Pole O&M Benchmarking

Distributor	Pole O&M - Unit Cost per Pole ($)					
	2018	2019	2020	2021	2022	Average
Alectra Utilities Corporation	$ 3.52	$ 3.00	$ 3.25	$ 4.60	-$ 0.01	$ 2.87
Canadian Niagara Power Inc.	$ 3.82	$ 5.09	$ 8.15	$ 6.08	$ 2.55	$ 5.14
Niagara Peninsula Energy Inc.	$ 4.88	$ 4.71	$ 7.56	$ 5.38	$ 8.02	$ 6.11
Niagara-on-the-Lake Hydro Inc.	$ 10.99	$ 13.31	$ 9.79	$ 9.78	$ 6.85	$ 10.14
Hydro One Networks Inc.	$ 12.30	$ 14.15	$ 14.31	$ 14.00	$ 13.93	$ 13.74
Welland Hydro-Electric System Corp.	$ 35.58	$ 18.26	$ 10.78	$ 14.79	$ 14.70	$ 18.82
Grimsby Power Incorporated	$ 13.04	$ 20.65	$ 28.59	$ 25.46	$ 16.28	$ 20.81
Regional Average						$ 11.09
Industry Average						$ 11.65

1.6.2.7 Station CAPEX

WHESC ranks third against the other five regional LDC's with substations on capital cost per MVA of transformer capacity installed. In 2022, WHESC completed a major upgrade of a municipal station involving replacement of all components including two 4 MVA power transformers. In the forecast period, WHESC has planned the replacement of two power transformers and primary cabling. The forecasted capital expenditure is lower that what occurred in the historical period which will result in lower average per unit capital costs moving forward.

Table 1-45: Station CAPEX per MVA Benchmarking

Distributor	Station CAPEX - Unit Cost per MVA ($)					
	2018	2019	2020	2021	2022	Average
Niagara Peninsula Energy Inc.	$ 82.98	$ 907.37	$ 42.90	$ 666.29	$ 395.50	$ 419.01
Alectra Utilities Corporation	$ 1,036.28	$ 218.61	$ 179.16	$ 1,131.15	$ 265.95	$ 566.23
Welland Hydro-Electric System Corp.	$ 3,259.73	$ 3,020.86	$ 4,361.17	$ 471.21	$11,001.55	$ 4,422.90
Hydro One Networks Inc.	$ 5,675.40	$ 6,847.83	$ 5,742.44	$ 5,488.08	$ 5,281.44	$ 5,807.04
Canadian Niagara Power Inc.	$ 2,576.15	$10,732.36	$ 4,641.21	$ 200.59	$20,501.43	$ 7,730.35
Regional Average						$ 3,789.11
Industry Average						$ 3,234.90

1.6.2.8 Poles, Towers Capex

WHESC ranks 4th in the group of regional LDCs for capital expenditures per pole addition. WHESC experienced cost increases on material and contract services in 2021 and 2022 due to COVID influenced procurement issues. Wood pole material costs have increased 91% between 2017 and 2023. Even with these cost pressures, WHESC is $18,568 below the industry average per addition.

Table 1-46: Pole CAPEX per Addition Benchmarking

Distributor	Pole CAPEX - Unit Cost per Pole Addition ($)					
	2018	2019	2020	2021	2022	Average
Grimsby Power Incorporated	$ 4,341.28	$ 3,616.82	$ 2,728.62	$ 6,289.73	$ 3,640.92	$ 4,123.47
Niagara-on-the-Lake Hydro Inc.	$ 5,879.91	$ 3,257.05	$ 4,757.38	$ 4,665.98	$ 2,261.62	$ 4,164.39
Canadian Niagara Power Inc.	$ 5,006.84	$ 5,527.03	$ 4,514.64	$ 5,954.15	$ 5,306.27	$ 5,261.78
Welland Hydro-Electric System Corp.	$ 4,780.14	$ 4,192.12	$ 3,994.60	$ 7,414.01	$ 7,566.69	$ 5,589.51
Niagara Peninsula Energy Inc.	$ 5,334.14	$ 4,471.56	$ 14,470.17	$ 8,063.87	$ 6,943.26	$ 7,856.60
Alectra Utilities Corporation	$ 16,719.62	$ 33,597.26	$ 17,934.83	$ 19,863.21	$ 33,137.93	$ 24,250.57
Hydro One Networks Inc.	TBD	TBD	TBD	TBD	$ 27,476.55	$ 27,476.55
Regional Average						$ 11,246.13
Industry Average						$ 24,157.90

1.6.2.9 Line Transformers Capex

WHESC ranks second in the regional cohort for capital cost per line transformer addition (ranking first with removal of the outlier). Similar to the circumstance with pole additions, WHESC experienced unit cost increases through 2022. WHESC's costs in this program are $10,063 lower per line transformer addition than the industry average.

Table 1-47: Line Transformer CAPEX per Addition Benchmarking

Distributor	Line Transformer CAPEX - Unit Cost per Line TX Addition ($)					
	2018	2019	2020	2021	2022	Average
Hydro One Networks Inc.	TBD	TBD	TBD	TBD	$ 823.15	$ 823.15
Welland Hydro-Electric System Corp.	$ 3,366.69	$ 6,980.54	$ 8,213.76	$ 7,832.57	$ 8,171.12	$ 6,912.94
Canadian Niagara Power Inc.	$ 6,385.26	$ 5,022.75	$ 7,337.28	$ 9,259.33	$ 7,076.89	$ 7,016.30
Grimsby Power Incorporated	$ 7,813.18	$ 7,565.93	$ 9,856.87	$ 4,076.54	$ 6,479.00	$ 7,158.30
Niagara-on-the-Lake Hydro Inc.	$ 12,193.89	$ 5,497.68	$ 6,575.54	$ 6,567.32	$ 7,701.39	$ 7,707.17
Niagara Peninsula Energy Inc.	$ 8,999.94	$ 9,758.82	$ 9,128.99	$ 9,978.77	$ 10,697.19	$ 9,712.74
Alectra Utilities Corporation	$ 20,250.61	$ 21,295.67	$ 20,509.95	$ 27,930.70	$ 42,511.28	$ 26,499.64
Regional Average						$ 9,404.32
Industry Average						$ 16,976.00

1.6.2.10 Meters Capex

WHESC ranks first in the regional cohort for meter capital expenditure per customer. There have been cost pressures on meters post-COVID, however WHESC believes that this has stabilized to some degree. The per unit cost is expected to remain consistent through the 2025 Test Year based on WHESC's capital expenditure projections.

Table 1-48: Meter CAPEX per Customer Benchmarking

Distributor	Meter CAPEX - Unit Cost per Customer ($)					
	2018	2019	2020	2021	2022	Average
Welland Hydro-Electric System Corp.	$ 4.29	$ 2.68	$ 2.03	$ 5.10	$ 4.45	$ 3.71
Grimsby Power Incorporated	$ 12.90	$ 11.38	$ 5.18	$ 8.30	$ 2.64	$ 8.08
Canadian Niagara Power Inc.	$ 10.16	$ 12.81	$ 16.14	$ 10.85	$ 0.00	$ 9.99
Alectra Utilities Corporation	$ 12.82	$ 15.87	$ 15.12	$ 11.96	$ 2.16	$ 11.59
Niagara-on-the-Lake Hydro Inc.	$ 12.28	$ 13.29	$ 15.47	$ 11.12	$ 6.36	$ 11.70
Niagara Peninsula Energy Inc.	$ 18.99	$ 21.32	$ 13.81	$ 24.50	$ 14.72	$ 18.67
Hydro One Networks Inc.	$ 53.84	$ 61.27	$ 66.35	$ 71.58	$ 74.35	$ 65.48
Regional Average						$ 18.46
Industry Average						$ 136.36

1.7 Facilitating Innovation

In line with the OEB's objective of facilitating innovation in the electricity sector, as outlined in the December 8, 2020, Section 1 of the OEB Act, WHESC has incorporated several innovative approaches to electricity distribution into the application. The first notable approach is the implementation of grid modernization strategies that ready the distribution system for real-time management of multi-directional power flow. The second is the implementation of a 24 x 7 system control operation at shared cost with a partner LDC. The third notable approach is the continued leveraging of shared services opportunities to improve service level at a managed cost profile.

1.7.1 Grid Modernization

WHESC proposes to continue investment in grid modernization by deploying additional devices on the distribution system to monitor voltage and power flow, faults and system disturbances. WHESC implemented a comprehensive protection philosophy on its main 27.6kV distribution system as described in the DSP found in Exhibit 2, Appendix 2-A. In order to manage increased DER penetration and load demographic changes from EV utilization, WHESC understands the need to have the highest level of real-time visibility into the distribution system. The deployment of SCADA controlled devices on the 27.6kV system makes up the majority of WHESC's planned investments in the System Service category.

Through the implementation of SmartMAP, WHESC has fully integrated GIS, SCADA, and AMI systems into a single platform that can perform real time power flow and analysis. This further leverages the technology deployments described above so that WHESC's system control staff can react to anomalies in real time on a 24 x 7 basis. WHESC's engineering staff can react to issues related to utilization and operating limits such as transformation that is over capacity or voltage performance outside of tolerance. The integrated solution allows for data analytics to determine where EV charging of significance is deployed or where DER infeed is occurring. WHESC intends to continue use of the hosted SmartMAP platform for the purpose of an Advanced Distribution Management System ("ADMS"), inclusive of Outage Management System workflows.

1.7.2 System Control Operation

The Minister of Energy issued a letter of direction to the OEB in 2022. In the context of "Distribution Sector Resiliency, Responsiveness, and Cost Efficiency", the letter indicated:

> *"Ontario's electricity distribution sector will have a critical role in Ontario's electrification transition. As the pace of the electrification of the economy increases and extreme weather events as a result of climate change impact our businesses and communities, there will be pressure on local distribution companies (LDCs) to continue to provide high levels of reliability and resiliency to their customers, be responsive to changing consumer expectations and new government mandates, and to do it all at an affordable price. This year, Ontario experienced two extreme weather events, which affected LDC infrastructure across Eastern Ontario. As our climate changes, the OEB will have an important role to play in ensuring LDCs are preparing their distribution infrastructure for these kinds of events. LDCs will need greater capacity to meet these expectations – capacity that can be enabled by aggressively pursuing efficiencies through consolidation or enhanced shared services, adoption of innovative technologies and processes, collaboration on responsibilities like cybersecurity, and changes to the utility remuneration and incentive structure that ensure LDCs make the right investments for their customers."*

In 2023, the OEB released a Report to the Minister of Energy titled "Improving Distribution Sector Resilience, Responsiveness, and Cost Efficiency". The report was in response to the Minister's Letter of Direction in 2022 referenced above in which the Ministry requested advice and proposals from the OEB to improve distribution sector resiliency, responsiveness and cost efficiency in relation to major weather events.

Major weather events impacting Ontario LDCs have increased in frequency in recent years as the impacts of climate change intensify. The items proposed in the report that WHESC has focused on are:

- Promote the greater sharing of services amongst distributors
- Integrating resilience into system planning
- Engage in regular data-driven assessments of vulnerabilities in the distribution system and operations in the event of severe weather
- Prioritize value for customers when investing in system enhancement for resilience purposes
- Measure and report on restoration of service
- Satisfy minimum targets for customer communication related to interruptions and restoration of service

In addition to investing in grid modernization, WHESC identified the need to maximize the benefit of technology deployments by having 24 x 7 system control coverage for remote operation of SCADA controlled devices. WHESC understands that implementing such a service as a mid-size LDC would put additional cost burden on the customers it serves and looked for innovative ways to provide a full coverage model at managed cost.

WHESC pursued opportunities to share system control costs with another LDC, Essex Powerlines Corporation (EPLC). In 2023, WHESC started its system control operation in house, acquiring resources for that purpose. In the first Quarter 2024, WHESC began covering EPLC's system control requirements. This approach was designed to provide both entities with 24 x 7 coverage at a shared and managed cost.

While both LDCs have invested significantly in remotely deployed grid modernization technology, both realized that sole implementation of a 24 x 7 coverage model was not cost effective to serve the needs of customers. The approach taken provides a significant increase in service level to the customers of both LDCs at a managed cost incremental. Both LDC's are better positioned to manage not only the current operating requirements but future requirements related to Distribution System Operator (DSO) workflows that become inevitable with increased DER presence.

1.7.3 Shared Services

WHESC continues the pursuit of cost efficiency through further consideration of shared services opportunities. In this application, WHESC has identified the need for a cyber-security specialist to oversee the LDC's regulatory compliance with applicable frameworks. Cyber-security risks continue to intensify along with exposure to same as end-point deployments on IT and OT systems expand. WHESC does not believe that an additional FTE is prudent given the level of expertise required and the size of WHESC's operation.

WHESC intends to leverage the existing a shared services arrangement with EPLC to acquire cyber-security compliance support in lieu of acquiring an FTE specifically for this purpose. This provides both LDCs an opportunity to increase the capacity of cybersecurity coverage under a shared cost model.

1.8 Financial Information

1.8.1 Audited Financial Statements

WHESC's Audited 2023 (2023/2022) and 2022 (2022/2021) Financial Statements have been included as Appendix 1-D and Appendix 1-E in this Exhibit.

1.8.2 Annual Report and MD&A

WHESC does not publish an annual report or an MD&A. As a result, this requirement is not applicable.

1.8.3 Rating Agency Report

WHESC does not have a rating agency report.

1.8.4 Prospectuses and Information Circulars for Recent and Planned Issuances

WHESC does not issue debt or shares, nor does it publish any prospectus.

1.8.5 Change in Tax Status

WHESC is not seeking any changes in its tax status. WHESC is a corporation, incorporated pursuant to the Ontario Business Corporations Act.

1.8.6 Existing Accounting Orders

In the 2017 COS application, the OEB approved an accounting order to establish a new deferral account, Account 1508 “Other Regulatory Assets, Sub-Account OPEB Actuarial Gains and Losses.” The OEB approved WHESC’s use of the cash methodology for the purposes of Other Post-Employment Benefit (“OPEB’s”) expenses in distribution rates. The new account was created to track cumulative changes in OPEB actuarial gains and losses as supported by an actuarial re-valuation. The current status and proposed future use of this account is described in detail in Exhibit 9.

In the 2017 COS settlement, it was agreed upon that WHESC would no longer record amounts to deferral and variance accounts 1508 Other Regulatory Assets, Sub-Account Deferred Transition cost and 1575 IFRS-CGAAP Transitional PP&E Amounts. WHESC confirms that it has not recorded any transactions to the above noted accounts.

1.8.7 Departures from USoA

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

1.8.8 Accounting Standards

WHESC uses International Reporting Standards (“IFRS”) for general purpose financial statements, effective January 1, 2015. For rate-making purposes, WHESC follows Modified International Reporting Standards (“MIFRS”). MIFRS was used in both WHESC’s 2017 COS application, as well as the current application.

1.8.9 Accounting Treatment of Non-Utility Business

WHESC has engaged in a limited amount of renewable generation activities since 2012. WHESC confirms that the accounting for these activities were segregated from WHESC's rate regulated activities in accordance with the Board's Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities G-2009-0300 dated September 15, 2009.

1.9 Distributor Consolidation

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

1.10 Impacts of COVID-19 Pandemic

The COVID-19 pandemic led to additional challenges and cost pressures that impacted the period from 2020 forward. WHESC has experienced significant increases in material and equipment costs, a strained labor market, and supply chain disruptions. This has affected WHESC's procurement costs, resource availability, and the ability to execute projects within planned timelines. While supply chain issues have started to ease, material costs and in some cases lead times, remain high. WHESC has factored these cost pressures into its budgeting process.

From a capital investment perspective, there has been some stabilization of material availability and lead-times. The effects of inflationary increases experienced since 2021 largely remain. Increases on material have exceeded 2x 2017 COS amounts in some cases, causing a permanent step change in the required capital expenditure for projects. Lasting effects remain on third-party service costs that have been influenced by inflationary changes in labour markets.

Impacts on OM&A are also related to increased material costs and third-party service provider costs. WHESC has taken steps to navigate these cost pressures through management of third-party provider costs for services such as locates and vegetation management. WHESC's objective remains to ensure that OM&A cost changes are in line with inflation and the influences of customer growth.

Appendix 1-A: WHESC Business Plan

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

2025-2029
FIVE-YEAR
BUSINESS PLAN

BUSINESS PLAN

2025 - 2029

Welland Hydro-Electric System Corp.

TABLE OF CONTENTS

1. BUSINESS OVERVIEW

2. REVENUES

3. OPERATING PLAN

4. CONTINUOUS IMPROVEMENT AND HUMAN RESOURCES

5. FINANCIAL PLAN

BUSINESS PLAN

SECTION 1 Business Overview

1.1 Executive Summary

Welland Hydro Electric System Corp.'s (WHESC) 2025 Business Plan represents management's evaluations and objectives during the five-year period from 2025 to 2029. The plan represents management's commitment to its shareholder, customers, and employees. WHESC has been one of the top performers within the Ontario Local Distribution Company (LDC) sector in many benchmarking categories, while maintaining lower distribution rates than some larger LDCs in the Province of Ontario.

Due to cost performance between 2018 and 2020, WHESC was identified as a "Cohort 1" LDC. Since 2020, WHESC remains in "Cohort 1". This achievement is based on meeting the deliverables of the previous business plan and management's commitment to gaining operating efficiencies.

Some of the key objectives outlined in this business plan include:

- A capital investment program which maintains or improves the reliability of the distribution system while accommodating load growth.
- Maintaining cost performance while improving reliability and reducing risk through the continued use of shared services.
- A new collective bargaining agreement effective April 1, 2026 which balances the needs of employees with both cost containment and productivity measures.
- Distribution rates that do not exceed the rate of inflation while allowing WHESC to maintain income levels within targets for return on equity.
- Customer satisfaction levels that remain higher than both the national and provincial average.

1.2 Corporate Statements & Strategic Objectives

Corporate Vision Statement

Welland Hydro will remain a community-owned asset and continue to collaborate with others, embracing best practices to implement appropriate product and service innovations in a timely manner within an ever-changing policy environment.

Corporate Mission Statement

Welland Hydro is a community-owned asset whose team of highly skilled professionals are committed to distributing safe, sustainable, reliable power that enhances the quality of life in Welland.

Strategic Objectives

- Deliver balanced financial and social returns by investing in quality distribution infrastructure
- Promote a culture of energy conservation and sustainable energy to our customers and employees that is consistent with the energy initiative of our shareholder and Province
- Be a leader in efficient, safe, reliable, and economic distribution of energy at competitive rates while providing the best value and quality for customers
- Provide a workplace environment which promotes innovation, communication, values, retains employees, and attracts personnel as required
- Enhance our position as an asset to our shareholder and the community by engaging all stakeholders in strategic objectives

1.3 Trends in the Industry

The industry continues to experience consolidation with recent asset sales and mergers. There are currently 57 LDCs with rates regulated by the Ontario Energy Board (OEB). Hydro One appears to continue focus on the acquisition of LDC assets in Ontario.

In 2022, two of the most recent significant mergers were approved by the OEB. The merger of Cambridge and North Dumfries Energy Plus Inc. with Brantford Energy Corporation is now completed, forming Grandbridge Energy. The merger of Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc. is also completed, forming Enova Power Corp.

Ministerial Directives

In October of 2022, the Honorable Todd Smith, Minister of Energy, released a renewed Letter of Direction to the OEB. In that letter and in the context of *"Distribution Sector Resiliency, Responsiveness, and Cost Efficiency"*, the letter indicated:

> *"Ontario's electricity distribution sector will have a critical role in Ontario's electrification transition. As the pace of the electrification of the economy increases and extreme weather events as a result of climate change impact our businesses and communities, there will be pressure on local distribution companies (LDCs) to continue to provide high levels of reliability and resiliency to their customers, be responsive to changing consumer expectations and new government mandates, and to do it all at an affordable price. This year, Ontario experienced two extreme weather events, which affected LDC infrastructure across Eastern Ontario. As our climate changes, the OEB will have an important role to play in ensuring LDCs are preparing their distribution infrastructure for these kinds of events. LDCs will need greater capacity to meet these expectations – capacity that can be enabled by aggressively pursuing efficiencies through consolidation or enhanced shared services, adoption of innovative technologies and processes, collaboration on responsibilities like cybersecurity, and changes to the utility remuneration and incentive structure that ensure LDCs make the right investments for their customers."*

LDCs continue to look to partnerships to increase efficiencies of scale and scope within their operations. Partnerships have the potential to reduce costs through shared services such as information technology, infrastructure procurement, and operating activities. The two significant cooperatives in place continue to be GridSmart City (GSC) for mid-size LDCs and the Cornerstone Hydro Electric Concepts (CHEC) association for smaller LDCs.

While WHESC continues to be a GSC member, collaboration through specific partnerships aimed at achieving efficiencies remains a strategic objective. In 2023, WHESC established a formalized shared services partnership for the provision of System Control Services to Essex Powerlines Corporation (EPLC). This initiative is specifically aimed at improving resiliency and responsiveness, providing both entities 24 x 7 grid visibility, oversight, and control at a shared and managed cost profile.

Electrification and Energy Transition Panel Report

In December of 2023, the Electrification and Energy Transition Panel (EETP) released its report: "Ontario's Clean Energy Opportunity". The Government of Ontario established the EETP to advise government on opportunities for the energy sector to help Ontario's economy prepare for electrification and the energy transition, and to identify strategic opportunities and planning reforms to support emerging electricity and fuels planning needs.

Of the 29 recommendations made in the report, management believes the following will have the greatest impact on WHESC as it relates to operations and planning:

Recommendation #17: To make full use of the innovation of distributed energy resources and the electricity distribution sector, the OEB and IESO must continue to find ways within their existing mandates and in anticipation of the clean energy economy policy commitment (Recommendation 1) to provide proactive and transparent thought leadership on regulatory policy and critically review and revise their existing policies and processes.

The aim of this recommendation as related to LDCs is generally to/for:

- realize the maximum capability of the distribution system and Distributed Energy Resources (DERs)
- the OEB should support LDC applications in grid modernization
- enable LDCs to locally procure and dispatch DERs
- require LDCs to enhance capabilities to procure and actively manage DERs
- the OEB should continue to enhance the requirement for LDCs to file Electrification Energy Plans (ERPs)

While only a recommendation at this stage, WHESC believes that its continued participation in shared services arrangements will be crucial and remain a necessary approach to meet the growing demand on LDCs, playing a pivotal role in DER adoption and grid modernization. The shared system control service is a major step forward allowing WHESC to maximize the benefit of system service-based investments. This approach positions WHESC to be ready for Distribution System Operator (DSO) model implementation should this become a reality in the near term. The 2025 Business Plan contains operational and capital investment strategies that continue to leverage a shared cost model, and additional investment to enhance grid visibility.

1.4 Government Regulations

In 2018, the Ontario Energy Board made amendments to the Distribution System Code (DSC) requiring LDC's to use an industry developed cyber security framework. On March 27th, 2024, the OEB issued Version 1.0 of the Ontario Cyber Security Standard with an effective date of October 1, 2024. The DSC was again amended to require compliance with the standard.

WHESC continues to acquire the necessary resources to maintain compliance. WHESC annually reports its status on cybersecurity compliance to the OEB. The maintenance of on premise and cloud-based IT systems via a third-party Managed Service Provider (MSP) continues in an effort to manage recurring OM&A impacts.

The Minister of Energy continues to be focused on affordability. On January 1st, 2023, amendments to the Standard Supply Service Code came into force requiring LDCs to offer the Ultra-Low Overnight Time of Use rate by November 1st, 2023. This enabled electricity consumers on the Regulated Price Plan to choose between time-of-use, ultra-low overnight, and tiered rates. LDC Customer Information and Billing Systems must continue to respond to changing billing requirements.

WHESC continues as a member of the GSC Cooperative. We continue to participate in purchasing arrangements for distribution system materials. We also continue to benefit from joint participation in initiatives such as an electrification strategy and Distribution System Operator (DSO) readiness strategy.

1.5 Risk Assessment

Acceleration of Residential Housing Development

The City of Welland has experienced significant residential growth over the past four years and this is expected to continue. New development is occurring in areas where existing assets cannot meet the capacity requirements. WHESC's capital investment plan continues to focus on replacing deteriorated assets while accommodating load growth. The accommodation of load growth places upward pressure on capital expenditures which is addressed in this five-year plan.

Supply Capacity

With the completion of the Integrated Regional Resource Planning (IRRP) cycle and release of the final report in December 2022, the IESO has confirmed that there is an immediate capacity and asset replacement need at Crowland TS. Regional Infrastructure Planning (RIP) processes are underway and the expected new Crowland TS in-service date is 2029. The five-year capital plan continues to address distribution circuit level capacity requirements. Included in this plan are investments in distribution level circuit interties to transformer stations outside of WHESC's territory to bridge the capacity gap that will exist prior to 2029.

Energy Transition / Electrification

The energy transition of transportation and heating sources will have a significant impact on LDCs given their role in meeting the associated electricity demands. WHESC in partnership with GridSmart City member LDCs, procured an Electrification Strategy Study. This study provides insight on potential EV adoption rates and heating fuel source switching along with recommendations on system preparedness. WHESC considered the potential adoption rates in producing this business plan. Recommendations on system preparedness that will affect this planning period have also informed the plan.

The transition requires LDC's to have greater real time visibility into the distribution system to understand asset utilization, operational and asset risk associated with load increase, and the impact of changes to power flow. WHESC uses its Advanced Distribution Management System, SmartMap, as a tool to identify portions of its distribution system where Level 2 or higher EV charging is deployed. This tool is also used to identify impacts of EV related load additions to the distribution system, informing planning decisions. WHESC is proactive in monitoring data analytics along with changing customer requirements to inform expenditure decisions.

Climate Change

In 2023, the OEB released a Report to the Minister of Energy titled "Improving Distribution Sector Resilience, Responsiveness, and Cost Efficiency". The report was in response to the Minister's Letter of Direction in 2022, requesting advice and proposals from the OEB to improve distribution sector resiliency, responsiveness and cost efficiency in relation to major weather events.

Major weather events impacting Ontario LDCs have increased in frequency in recent years as the impacts of climate change intensify. The items proposed in the report that WHESC has focused on are:

- Promote the greater sharing of services amongst distributors
- Integrating resilience into system planning
- Engage in regular data-driven assessments of vulnerabilities in the distribution system and operations in the event of severe weather

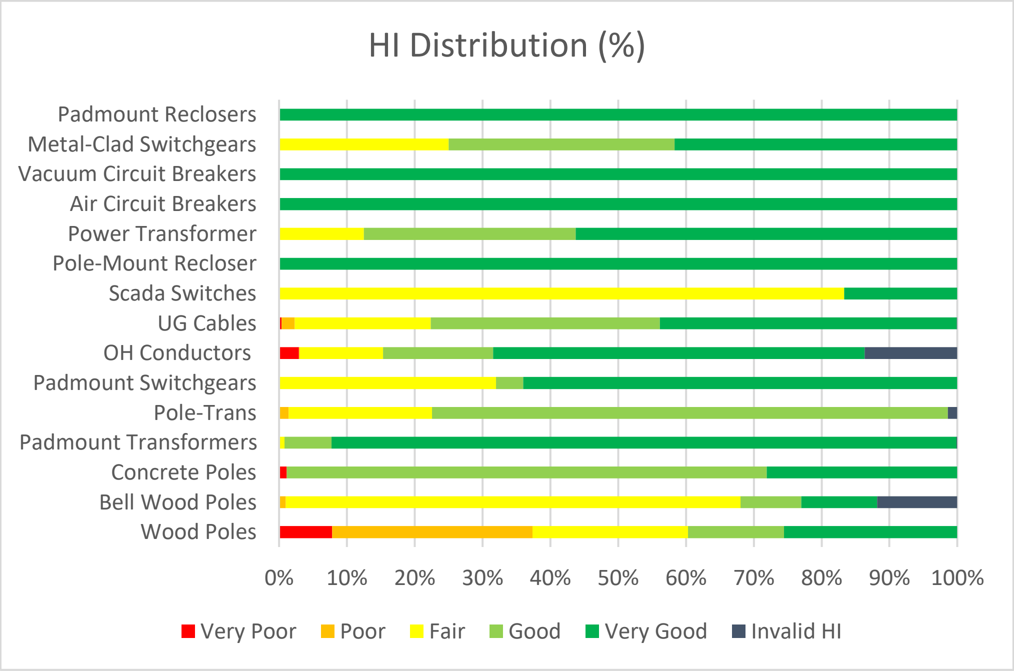
- Prioritize value for customers when investing in system enhancement for resilience purposes
- Measure and report on restoration of service
- Satisfy minimum targets for customer communication related to interruptions and restoration of service

WHESC plans to continue investment in grid modernization with technology deployments that benefit grid visibility. To maximize the benefit of technology deployments, WHESC leverages its 24 x 7 system control operation. This allows WHESC to operationally position itself to manage high impact events. The system control operation was implemented with EPLC, sharing the same resiliency and grid visibility objectives. WHESC believes that this, along with its asset management-based decisions prioritizes the value for customers in improving our resiliency posture. Customer engagement in support of the Distribution System Plan (DSP) confirms that there is a desire to ready our distribution system in advance of significant weather events.

Asset Health

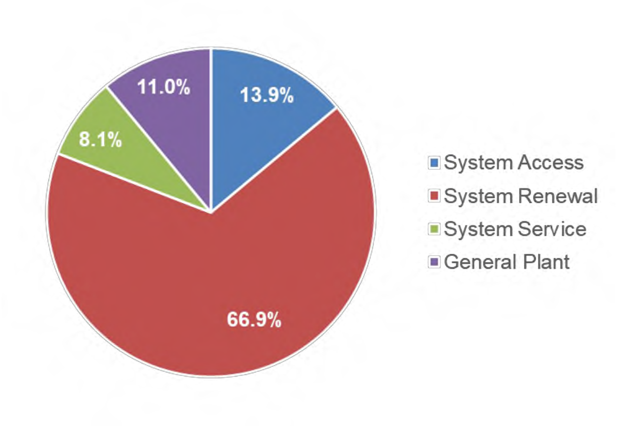
WHESC's DSP is informed by a comprehensive Asset Condition Assessment (ACA) that was conducted in 2023. The resulting asset health indices are a significant driver of WHESC's planned capital investments. A summary of the Health Index Distribution is shown in Figure 1-1, below.

Figure 1-1: Health Index Distribution



A significant portion of WHESC's planned net capital investments are categorized as System Renewal (67%) as shown in Figure 1-2, below. These investments directly target the replacement of deteriorated assets identified in Figure 1-1. Welland Hydro continues to invest in sustaining distribution system integrity based on reliability and resiliency objectives.

Figure 1-2: DSP Investment Categories



Cybersecurity

Risks associated with cybersecurity continue to be accommodated in this business plan. WHESC will continue to manage IT operating and maintenance activities using third party MSPs where feasible. WHESC's has included investments in sustaining on premise IT/OT infrastructure in the five-year plan. WHESC has also budgeted for additional resources to meet the ever-changing cybersecurity requirements. WHESC intends to further leverage its shared services arrangement with EPLC to manage incremental resource costs.

2.1 Customers

The customer count by classification is shown below in Table 2-1. Growth in the Residential customer class is based on a review of subdivision agreements currently in place as shown in Table 2-2. In addition to the subdivision agreements noted in Table 2-2, additional phases in the Dain City East and Dain City West developments are anticipated. Development is also expected to occur in the northwest portion of Welland as part of the regionally approved urban area expansion. Additionally, development is anticipated to occur in the "Northern Reach" area.

The remainder of phases contemplated in the Dain City East and West developments account for an additional 1,948 units alone that are not shown in Table 2-2. As a result, the forecast for residential units is conservative and reflects strong growth expected in the City of Welland.

The customer count for all other classifications have been derived from load forecast model data supporting the cost of service with minor adjustments. Given the continued economic development activity in the City of Welland, the five-year plan for both General Service customer classifications should be considered conservative. The reduction in Sentinel Light connections is based on reductions in this classification over the past five years.

Table 2-1: Customer Count

	Customer Count/Connections							
Customer Class	**July 2024**	**Plan 2024 Average**	**Plan 2025 Average**	**Plan 2026 Average**	**Plan 2027 Average**	**Plan 2028 Average**	**Plan 2029 Year End**	**Growth 2024 to 2029**
Residential	23,835	23,886	24,119	24,352	24,602	24,852	25,102	1,268
GS<50 kW	1,853	1,845	1,869	1,869	1,869	1,869	1,869	16
GS 50 to 4,999 kW	147	148	137	137	137	137	137	-10
Unmetered Load	196	196	189	189	189	189	189	-7
Sentinel Lights	341	321	311	311	311	311	311	-30
Street Lights	7,296	7,272	7,464	7,464	7,464	7,464	7,464	168

Table 2-2: New Residential Development Summary

SA #	Name	Total Lots	Total Lots Developed	Available Lots
95	Dain City West- Phase 1	200	0	200
93	Harvest Oak	57	0	57
92	175 Southworth - Phase 1	15	13	2
91	Stoneybrook Crescent	7	0	7
90	Dain City East Phase 2	173	58	115
89	Superior Road Development	16	0	16
87	162 Hagar Street Development	10	0	10
86	201 Ontario Rd	106	19	87
85	West Creek Condominium	70	0	70
84	The Residences of Lochness - North Village phase 5 Stage 2 &3	52	3	49
83	Residences of Lochness North Village Phase 5 Stage 1	27	12	15
82	Hansler Village Condomimium	43	9	34
80	200 West Main St Phase 2	43	26	17
79	Kingsway Subdivision	167	0	167
72	Gorge Meadows	25	7	18
71	Canal Trail Estates	31	0	31
69	Dain City East Phase 1	288	269	19
67	Murdoch Estates Phase 1	66	14	52
66	Westwoods on the Creek Phase 2	74	3	71
65	Chaffey St Phase 3	17	0	17
61	The Residences of Lochness -North Village Phase 4	27	23	4
60	Welland Rivera Estates	8	4	4
59	Vanier Estates Phase 4	44	6	38
54	Pines Estates	11	10	1
51	Vanier Estates - Phase 3	34	31	3
49	The Residences of Lochness -North Village Phase 3	65	64	1
47	The Residences of Lochness - Lochness Central Phase 1	80	77	3
42	Sparrow Meadows Phase 3 & 4	101	100	1
36	Vanier Estates - Phase 1 & 2	34	33	1
	Totals	**2807**	**1697**	**1110**

2.2 Distribution Rates

Distribution rates for the 2025 Five-Year Plan are shown below in Table 2.3. The business plan is based upon 2024 IRM approved distribution rates, the 2025 Cost of Service rates as filed, and inflation at 2.0% per year for each year from 2026 through to 2029.

The OEB benchmarks distributors' total cost performance each year. The results are used to determine stretch factors that can reduce rates charged to customers through annual IRM applications. Stretch factors incent distributors to perform better, and promote, recognize and reward distributors for cost efficiency improvements. As a result of its commitment to cost efficiencies, WHESC remains in Cohort 1 (stretch factor = 0.00).

The annual inflation rate approved by the OEB is derived from prior year inflation factors and employment indicators.

Table 2.3: Distribution Rates

	Charge Type	Actual 2024	Plan 2025	Plan 2026	Plan 2027	Plan 2028	Plan 2029
Residential	Monthly	32.35	32.83	33.49	34.16	34.84	35.54
Residential	Usage	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
GS<50 kW	Monthly	36.94	36.94	37.68	38.43	39.20	39.99
GS<50 kW	Usage	0.0109	0.0113	0.0115	0.0118	0.0120	0.0122
GS 50 to 4,999 kW	Monthly	336.30	336.30	343.03	349.89	356.88	364.02
GS 50 to 4,999 kW	Usage	3.6264	3.6984	3.7724	3.8478	3.9248	4.0033
Unmetered Load	Monthly	12.32	12.14	12.38	12.63	12.88	13.14
Unmetered Load	Usage	0.0081	0.0080	0.0082	0.0083	0.0085	0.0087
Sentinel Lights	Monthly	4.53	5.12	5.22	5.33	5.43	5.54
Sentinel Lights	Usage	10.1625	11.4823	11.7119	11.9462	12.1851	12.4288
Street Lights	Monthly	0.71	0.70	0.71	0.73	0.74	0.76
Street Lights	Usage	3.0103	2.9684	3.0278	3.0883	3.1501	3.2131

WHESC compares its distribution rates with other LDCs in Ontario with an emphasis on being below the provincial average rate in every customer class. Comparisons with distribution rates at neighbouring LDC's in the Niagara Peninsula are shown below in Table 2.4 for the Residential and General Service customer classes.

Table 2.4: Distribution Rate Comparison

Distributor		Welland	Welland Ranking	Niagara Falls	Alectra St. Catharines	Grimsby	N.O.T.L.	CNP FE & Port
Customer class	**Charge Type**	**Actual 2024**	**Actual 2024**	**Actual 2024**	**Actual 2024**	**Actual 2024**	**Actual 2024**	**Actual 2024**
Residential	Monthly	$32.35		$39.29	$30.80	$32.69	$33.13	$45.05
Average Consumption	2024	750		750	750	750	750	750
Total Distribution Charges		$32.35	2nd	$39.30	$30.80	$32.69	$33.13	$45.05
GS<50 kW	Monthly	36.94		46.73	48.77	28.68	43.56	40.74
GS<50 kW	Usage	0.0111		0.0183	0.0134	0.0251	0.0140	0.0311
Average Consumption	2024	2000		2000	2000	2000	2000	2000
Total Distribution Charges		$59.14	1st	$83.33	$75.61	$78.88	$71.56	$102.94
GS 50 to 4,999 kW	Monthly	336.30		144.96	449.12	238.13	311.31	277.62
GS 50 to 4,999 kW	Usage	3.6813		4.5715	3.0259	4.5756	2.7766	8.6536
Average Consumption	2024	250		250	250	250	250	250
Total Distribution Charges		$1,256.63	3rd	$1,287.84	$1,205.59	$1,382.03	$1,005.46	$2,441.02

Table 2.4 shows that WHESC's 2024 Distribution Rates continue to be very competitive and reflect some of the lowest rates in the surrounding area. Monthly Residential Distribution Rates are second only to Alectra which has a customer base over 40 times that of WHESC. WHESC's General Service customers have monthly distribution charges significantly below neighbouring LDCs.

The General Service 50 to 4,999 kW class is a difficult class to compare with other LDCs because of significant differences in monthly fixed versus volumetric rates. This will impact a customer's total distribution charges based on the magnitude of their monthly demand. For example, customers with larger demand benefit when the fixed portion of the rate is higher and the variable component is lower. These customers would have higher monthly distribution rates in Grimsby, Niagara Falls, Fort Erie and Port Colborne compared to Welland.

2025 Business Plan Deliverables

- **WHESC maintains its position of having distribution rates below the provincial average and at or near the lowest rates in the Niagara Peninsula for all customer classes.**

2.3 Distribution Revenues

Table 2.5 below summarizes the planned customer count, consumption, and distribution rates to determine Distribution Revenue for the 2025 Five-Year Plan.

Table 2.5: Distribution Revenue

DISTRIBUTION REVENUE							
2025 FIVE YEAR PLAN							
	2017	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	Full Year	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**
	COS	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Distribution Services Revenue-Monthly							
Residential	5,616,330	9,130,809	9,501,478	9,681,564	10,035,702	10,400,132	10,775,125
General Service Less Than 50 kw	659,221	805,409	828,454	839,582	856,374	873,501	890,971
General Service 50 to 4999 kw	521,478	588,156	554,005	560,254	571,459	582,888	594,546
Unmetered Scattered Load	32,295	28,545	27,529	28,325	29,961	30,560	31,172
Sentinel Lighting	23,180	18,243	19,128	17,121	17,464	17,813	18,169
Street Lighting	49,360	61,238	62,701	64,681	65,974	67,294	68,640
Total Distribution Revenue Monthly	**6,901,864**	**10,632,400**	**10,993,295**	**11,191,528**	**11,576,934**	**11,972,189**	**12,378,624**
Distribution Services Revenue-Volumetric							
Residential	1,221,563	0	0	0	0	0	0
General Service Less Than 50 kw	488,945	576,153	637,123	622,718	635,172	647,876	660,833
General Service 50 to 4999 kw	1,183,534	1,281,332	1,365,469	1,356,736	1,383,871	1,411,548	1,439,779
Unmetered Scattered Load	6,573	6,770	6,434	6,577	6,708	6,842	6,979
Sentinel Lighting	17,527	10,858	12,113	10,864	11,081	11,303	11,529
Street Lighting	9,023	11,819	12,309	12,649	12,902	13,160	12,906
Total Distribution Revenue Volumetric	**2,927,165**	**1,886,931**	**2,033,448**	**2,009,544**	**2,049,735**	**2,090,729**	**2,132,027**
Transformer Allowance-GS<50 kw	- 10,103	- 7,255	- 7,256	- 7,255	- 7,255	- 7,255	- 7,255
Transformer Allowance-GS 50 to 4999 kw	- 134,901	- 112,901	- 112,902	- 112,901	- 112,901	- 112,901	- 112,901
Total Transformer Allowance	**- 145,004**	**- 120,156**	**- 120,157**	**- 120,156**	**- 120,156**	**- 120,156**	**- 120,156**
Distribution Revenue Fixed & Variable Rates	**9,684,025**	**12,399,174**	**12,906,586**	**13,080,915**	**13,506,513**	**13,942,763**	**14,390,495**
LRAM Revenue	**-**	**21,275**	**-**	**-**	**-**	**-**	**-**
Monthly Service Charge-SSA Administration	66,737	77,282	78,261	79,500	80,700	81,900	83,100
Monthly Service Charge-Microfits	10,800	13,992	13,992	13,992	13,992	13,992	13,992
Retail Service Revenue Charge	10,339	8,489	3,512	3,582	3,653	3,726	3,801
Service Trans Revenue	498	83	83	83	83	83	83
Rate Protection Revenue	-	5,172					
Tax Variance-Revised Accelerated CCA	-	- 75,955					
Total Distribution Revenue	**9,772,399**	**12,449,513**	**13,002,433**	**13,178,072**	**13,604,941**	**14,042,464**	**14,491,470**

2.4 Other Revenues

Other Revenue for the 2025 Five-Year Plan is reflected in Table 2.6 below. Rental from joint use pole attachments is planned to increase in 2025 due to migration to the updated OEB approved rate. Interest income is forecast to decrease in anticipation of cyclical rate reductions in the forecast period.

Table 2.6: Other Revenue

DETAILED OTHER REVENUE							
2025 FIVE YEAR PLAN							
	2017	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	Full Year	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**
	COS	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Miscellaneous Operations Revenue							
Rent from Electric Property-Poles	139,958	149,186	223,902	266,466	271,806	277,213	282,753
Rent from Solar Facility	0	10,000	10,000	10,000	10,000	10,000	10,000
Rent from Electric Property-Service Center	24,599	0	0	0	0	0	0
Rent from Electrical Property	**164,557**	**159,186**	**233,902**	**276,466**	**281,806**	**287,213**	**292,753**
Late Payment Charges	73,781	106,410	106,410	106,410	106,410	106,410	106,410
Late Payment Charges	**73,781**	**106,410**	**106,410**	**106,410**	**106,410**	**106,410**	**106,410**
Misc-Service-Account Status Fee	1,096	100	100	100	100	100	100
Misc Service-NSF Charges	3,984	12,315	12,315	12,315	12,315	12,315	12,315
Misc Service-Occupancy Related	104,263	114,330	114,330	114,330	114,330	114,330	114,330
Misc Service-Disconnect/Reconnect	52,438	25,010	25,010	25,010	25,010	25,010	25,010
Misc Service-Mark Up on Work Orders	28,048	35,000	35,000	35,000	35,000	35,000	35,000
Miscellaneous Service Charges	**189,829**	**186,755**	**186,755**	**186,755**	**186,755**	**186,755**	**186,755**
Gain on Disposition of Utility and Other Property	8,428	2,000	2,000	2,000	2,000	2,000	2,000
Loss on Premature Asset Disposition	-29,320	-6,000	-6,000	-6,000	-6,000	-6,000	-6,000
Gain on Disposition of Property	**-20,892**	**-4,000**	**-4,000**	**-4,000**	**-4,000**	**-4,000**	**-4,000**
Scrap Metal Sales	25,268	15,000	15,000	15,000	15,000	15,000	15,000
Misc Service-Other Revenue	4,311	100	100	100	100	100	100
Miscellaneous Non Operating Income	**29,579**	**15,100**	**15,100**	**15,100**	**15,100**	**15,100**	**15,100**
Total Other Misc Operations Revenue	**436,854**	**463,451**	**538,167**	**580,731**	**586,071**	**591,478**	**597,018**
Interest Earned							
Interest Income-Bank & Miscellaneous	4,906	222,520	100,000	70,000	70,000	70,000	70,000
Interest Income-Variance Accounts	0	0	0	0	0	0	0
Interest and Dividend Income	**4,906**	**222,520**	**100,000**	**70,000**	**70,000**	**70,000**	**70,000**
Total Other Operating Revenue-Distribution	**441,760**	**685,971**	**638,167**	**650,731**	**656,071**	**661,478**	**667,018**
Mark UP/Incentive-OPA/CDM Programs	0	0	0	0	0	0	0
Solar Expense	0	-2,000	0	0	0	0	0
Solar Revenue	0	25,385	0	0	0	0	0
CDM Revenue		0	0	0	0	0	0
Total Miscellaneous Operating Non Distribution	**0**	**23,385**	**0**	**0**	**0**	**0**	**0**

3.1 Operating, Customer Service, and Administrative Expenses (OM&A)

The 2025 Five-Year Plan OM&A expenses are detailed below in Table 3.1.

Table 3.1: OM&A Expenses

	2017	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	Full Year	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**
	COS	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Expenses							
Operations & Maintenance	3,314,316	4,175,132	4,705,050	4,889,369	5,063,281	5,182,064	5,336,253
Customer Service	1,611,467	1,707,242	1,835,009	1,896,032	1,957,722	2,015,687	2,079,400
Administration	1,874,217	2,223,426	2,283,599	2,283,313	2,378,143	2,435,589	2,526,754
Total OM&A Expenses	**6,800,000**	**8,105,801**	**8,823,658**	**9,068,714**	**9,399,147**	**9,633,339**	**9,942,408**
Increase from 2017 COS			**29.8%**				
Average Increase Annually			**3.7%**				
Increase Year over Year			8.86%	2.78%	3.64%	2.49%	3.21%

The 2025 planned OM&A is 29.8% above the 2017 OEB approved levels. This is an average annual increase of 3.7%. Inflationary increases over the period from 2018 through to 2025, based on OEB inflation factors, total 24.5% (compounded). OM&A is also influenced by growth increases over the period which total 6.5% (compounded). The OM&A increase of 29.8% over the period demonstrates that WHESC is managing costs inline with growth and inflation.

Primary Cost drivers of OM&A between 2017 and 2025 are:

- Wages and Benefits: WHESC has reduced its FTE count over the period, managing the overall increase in OM&A due to wages and benefits to 13.1% over the period.
- Billing Contract Services: WHESC has migrated to third-party bill processing in order to manage associated operating expenditures. This provides WHESC with resource depth and redundancy without upward pressure on FTE count. A reduction of 1.5 FTE's occurred due to outsourcing resulting in a reduction in overall costs for bill processing.
- Information Systems and Support: IT and OT operating costs have increased by approximately $150K over the period. WHESC has managed costs by making strategic decisions to migrate from fully hosted solution costs by bringing critical systems on premise. Additionally, WHESC changed its third-party Managed Service Provider (MSP) during the period. Cyber-security services costs have placed upward pressure on information system expenditures.
- Locates: Costs for performing third-party utility locates have increased throughout the period due in part to volume increases. Third-party service provider costs have increased

by 1.5x 2017 rates post-COVID. WHESC changed its third-party service provider in 2024 in order to manage the impact of rate increases.

- Materials: Costs associated with materials issued for operational and maintenance activities have increase by $122K over the period. This is largely due to significant material costs increases post-COVID.

- Postage and Bill Delivery: WHESC has changed its mechanism of delivering bills to customers, resulting in a net increase of approximately $50K incremental to OM&A, largely due to postage cost increases.

- Advanced Distribution Management System (ADMS) Software: Implementation of WHESC's SmartMAP solution to provide real-time distribution management capability is associated with an approximate increase of $80K to OM&A annually. The platform is hosted and subscription based.

- Vegetation Management: Tree trimming cost increases have been managed over the period to limit the cost increase to approximately $80K. There have been significant pressures on third-party costs for tree clearing services since 2017.

The drivers listed above account for approximately $1.4M of the increase in OM&A expenditure since 2017. The balance of the increase is generally associated with inflationary increases on goods and services over the period. Between 2026 and 2029, costs were generally inflated by 3% unless a rate is known based on contractual arrangements.

3.2 Capital Expenditures & Depreciation Expenses

Table 3.2 below contains WHESC's detailed capital expenditures by class for the 2025 Five-Year Plan. Expenditures for 2025 to 2029 are detailed in WHESC's updated Distribution System Plan which maintains our commitment to maintaining a safe and reliable distribution system with continuous improvement.

System Access expenditures include capital contributions to new residential developments based on historical experience. The increased rate of new development is expected to continue. Also included in this investment category are expenditures and offsetting contributions for road relocations and system expansions. Investment in metering is expected to increase inline with residential and commercial growth.

System Renewal projects include substation, overhead, and underground rebuilds with a focus on replacing deteriorated assets while accommodating growth. Overhead rebuild designs in this category consider the accommodation of additional capacity in areas of anticipated load additions.

System Service investments focus on the implementation of automated switch and fault indicating devices. In order to maintain system reliability while accommodating new connections, these devices permit additional automated sectionalizing. This directly reduces the impact to customers during unplanned events.

General Plant expenditures include computer hardware and software, automotive equipment and building repairs. The 2025 Five-Year Plan reflects WHESC's commitment to maintaining its existing fleet of light and heavy-duty vehicles. Computer hardware and software expenditure requirements have stabilized since the implementation of on-premise IT infrastructure along the utilization of a third-party MSP for operating and maintenance activities.

2025 Business Plan Deliverables

- **80% of Capital Projects related to System Renewal are started or completed in the year in which they are planned.**
- **WHESC's asset condition assessment (ACA) is updated based on current data. The distribution system plan will be updated based on the results of the ACA.**
- **Circuit level capacity is addressed to accommodate forecasted load growth.**

Table 3.2: Capital Expenditures

DETAIL CAPITAL SPENDING - 2025 FIVE YEAR PLAN	2024 Budget	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2025-2029 Five Year Plan
System Access							
Municipal Relocations/Line Expansions							
M21 - 27.6kV Line Extension	625,000						0
Southworth 27.6kV Line Extension	80,000						0
Clare Avenue - 27.6 kV - Line Extension	93,600						0
Contributed Capital	-774,600						0
Sub-Total Municipal Relocations - Net Capital	**24,000**	**0**	**0**	**0**	**0**	**0**	**0**
Residential Services							
New Overhead/Underground Service Connections	45,000	46,350	47,741	49,173	50,648	52,167	246,078
Subdivision Expansions							
Subdivisions Gross Capital	1,103,000	1,136,000	1,170,000	1,205,000	1,242,000	1,279,000	6,032,000
Contributed Capital	-803,000	-827,000	-852,000	-878,000	-904,000	-931,000	-4,392,000
Expansions (Subdivisions)	**300,000**	**309,000**	**318,000**	**327,000**	**338,000**	**348,000**	**1,640,000**
General Services							
General Services	232,780	239,763	246,956	254,365	261,996	269,856	1,272,936
Contributed Capital (Transformers/Meters)	-142,863	-147,149	-151,563	-156,110	-160,794	-165,617	-781,234
General Services	**89,917**	**92,614**	**95,393**	**98,255**	**101,202**	**104,238**	**491,703**
Retail Meters							
Retail Meters	150,000	154,500	159,135	163,909	168,826	173,891	820,261
Sub-Total System Access	**608,917**	**602,464**	**620,268**	**638,336**	**658,677**	**678,297**	**3,198,043**
System Renewal Projects							
Substation Renewal							
MS 5 TX Replacement / HV Cables		330,000					330,000
MS 7 TX Replacement / HV Cables				300,000			300,000
MS-7 - Relay Upgrade		30,000					30,000
Sub-Total Substation Renewal	**0**	**360,000**	**0**	**300,000**	**0**	**0**	**660,000**
Overhead Line Renewal							
M21 Rebuild: Canal Bank from Forks Rd to Towline Tunnel Rd Ph-2	250,000						0
M22 Rebuild: Welland River Crossing	75,000						0
Talbot Rd. 27.6kV Conversion	125,000						0
Dain Ave. Rebuild	550,000						0
Dain Ave. Area Voltage Conversion	200,000						0
Humberstone Rd. Pole Replacements	200,000						0
Plymouth at McLean Coversion Rebuild	75,000						0
Lincoln / Dunkirk Rebuild	100,000						0
Netherby at Railway Crossing / Reaker Rd. Conversion	125,000						0
Bishop / McNaughtion - Rebuild / Conversion 2.4KV to 16KV		300,000					300,000
First St, Second St - Rebuild / Conversion 2.4KV to 16KV.		250,000					250,000
Thorold Rd - Clare Ave to Rose Ave -Rebuild / Conversion		500,000					500,000
Lincoln - Plymouth to King - Rebuild			300,000				300,000
McArthur Ave, Morningstar Ave - Rebuild / Conversion 2.4KV to 16KV			600,000				600,000
Clare Ave - Fitch St to Thorold Rd - Rebuild / Conversion 4.16KV to 27.6KV			725,000				725,000
First Ave - Woodlawn to Quaker - Rebuild / Conversion				750,000			750,000
Ontario Rd - Memorial Park Dr / Hydro Corrdidor - Rebuild / Conv.				195,000			195,000
Lyons Creek Rd, Darby St - Rebuild / Conversion					600,000		600,000
State St, Kent St, Albet St - Rebuild / Conversion					600,000		600,000
King St - Regent St to Lincoln St - Rebuild / Conversion					192,000		192,000
Quaker Rd @ First Ave - Rebuild / Conversion						300,000	300,000
E. Main St - Myrtle Ave to Scholfield Ave - Rebuild / Conversion						300,000	300,000
Sub-Total Overhead Line Renewal	**1,700,000**	**1,050,000**	**1,625,000**	**945,000**	**1,392,000**	**600,000**	**5,612,000**

DETAIL CAPITAL SPENDING - 2025 FIVE YEAR PLAN	2024 Budget	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2025-2029 Five Year Plan
Underground Line Renewal							
98 Woodlawn Re-servicing	100,000						0
Dover / Dunkirk - Rebuild / Conversion		550,000					550,000
Leonard Ave, Donna Marie Dr - Rebuild / Conversion			540,000				540,000
Summit Ave, Linwood Dr,Home St- Rebuild / Conversion				570,000			570,000
St Andrews Ave, Hagar Street - Rebuild / Conversion					360,000		360,000
Erin Cres, Steven St - Rebuild / Conversion					250,000		250,000
Sharon Ave, Walt St - Rebuild / Conversion					230,000		230,000
Northgate Dr - Rebuild / Conversion						380,000	380,000
Glenwood Pky, Crescent Dr - Rebuild / Conversion						795,000	795,000
Apple Cres, Brant Ave - Rebuild / Conversion						250,000	250,000
Glenayr Pl, McColl Dr, Briarfield Cres - Rebuild / Conversion						250,000	250,000
PMH-9 Switchgear Replacements	250,000	257,500	265,225	273,182	281,377	289,819	1,367,103
Sub-Total Underground Line Renewal	**350,000**	**807,500**	**805,225**	**843,182**	**1,121,377**	**1,964,819**	**5,542,103**
Miscellaneous Renewal							
Miscellaneous Pole Replacements	150,000	302,387	311,459	320,803	330,427	340,340	1,605,415
Miscellaneous Transformer Replacements	80,000	161,273	166,111	171,095	176,228	181,514	856,222
Miscellaneous Underground Rebuild	50,000	51,500	53,045	54,636	56,275	57,964	273,420
Miscellaneous Overhead Primary	75,000	151,194	155,729	160,401	165,213	170,170	802,708
Sub-Total Miscellaneous Renewal	**355,000**	**666,354**	**686,345**	**706,935**	**728,143**	**749,988**	**3,537,765**
Sub-Total System Renewal Projects	**2,405,000**	**2,883,854**	**3,116,570**	**2,795,117**	**3,241,520**	**3,314,807**	**15,351,868**
System Service							
Scada/Substation System Service							
Scada Reclosures/Vipers	150,000	231,750	238,703	245,864	253,239	260,837	1,230,392
SEL - Fault Indicators	10,000	10,300	10,609	10,927	11,255	11,593	54,684
Lincoln St, Conventry - 27.6KV Extension / Tie					100,000		100,000
M14 - Allanburg TS Intertie			250,000				250,000
M19 - Alanburg TS Intertie Re-enforcement				225,000			225,000
Sub-Total System Service	**160,000**	**242,050**	**499,312**	**481,791**	**364,495**	**272,429**	**1,860,076**
General Plant							
Furniture & Equipment							
Furniture & Equipment	**20,000**	**50,000**	**18,000**	**5,200**	**5,356**	**5,517**	**84,073**
Information Systems							
Information Systems	**27,640**	**140,000**	**41,115**	**46,014**	**20,496**	**21,110**	**268,734**
Measurement & Testing Equipment							
Measurement & Testing Equipment	**22,500**	**100,000**	**20,000**	**20,600**	**0**	**45,000**	**185,600**
Tools							
Tools	**10,300**	**10,609**	**10,927**	**11,255**	**11,593**	**11,941**	**56,325**
Automotive Equipment &Vehicles							
2024 / 2029 Light Vehicle - (Operations)	65,000	66,950	68,959	71,027	73,158	75,353	355,447
46' Bucket Truck - (2025 / 2026)			145,142	394,851			539,993
55' Bucket Truck - (2024)		377,021					377,021
Compact Utility Tractor - (Replacement for Loader)					80,000		80,000
Reel Trailer		85,000					85,000
Sub-Total Automotive Equipment & Vehicles	**65,000**	**528,971**	**214,100**	**465,879**	**153,158**	**75,353**	**1,437,461**
Buildings & Grounds							
Service Centre Parking Lot Repaving	219,630						0
Building Upgrade - Plan	170,000	125,000	194,000	32,500	35,000	112,500	499,000
Sub-Total Buildings & Grounds	**389,630**	**125,000**	**194,000**	**32,500**	**35,000**	**112,500**	**499,000**
Sub-Total General Plant	**535,070**	**954,580**	**498,142**	**581,447**	**225,602**	**271,420**	**2,531,192**
Total Capital Net	**3,708,987**	**4,682,949**	**4,734,292**	**4,496,692**	**4,490,294**	**4,536,953**	**22,941,179**

4.1 Continuous Improvement & Human Resource Plan

WHESC's 2025 Five-Year Business Plan continues to focus on productivity improvements in capital expenditures, operating expenses, and benchmarking indices to meet the expectations of its shareholder, Board of Directors, customers and regulatory requirements.

WHESC has leveraged shared services where possible to manage OM&A expenditures through headcount reduction. The targeted headcount reduction identified in the 2017 COS was exceeded. Table 4.1 summarizes the FTE movement that has occurred between the 2017 COS levels and the 2025 Plan.

Table 4.1: FTEs by Department

Department	2017 Test Year OEB Approved	2017 Acutal	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year	Change from 2017 COS
Billing & Collecting	9.3	8.3	8.0	7.3	7.0	7.0	6.7	6.0	5.3	5.3	- 4.0
Finance & Regulatory	3.0	3.0	3.0	2.7	2.0	2.0	2.0	2.2	2.8	3.0	-
Engineering	5.7	5.0	5.3	6.2	5.3	4.8	4.6	4.4	5.3	7.3	1.6
Metering	3.0	3.0	1.7	1.3	2.0	2.0	2.0	2.0	2.0	2.0	- 1.0
System Control	1.0	1.0	1.0	1.0	1.0	0.6	-	0.4	3.0	3.0	2.0
Operations	16.0	15.7	15.6	17.1	16.6	16.3	15.2	15.5	15.0	16.0	-
Administration	3.0	2.0	2.0	2.0	2.0	2.2	2.0	2.0	2.0	2.0	- 1.0
Total FTEs	41.0	38.0	36.6	37.6	35.9	34.9	32.4	32.3	35.5	38.7	- 2.3
Resource Costs Allocated to Shared Service Recipient									1.4	1.4	
WHESC FTEs	41.0	38.0	36.6	37.6	35.9	34.9	32.4	32.3	34.1	37.3	- 3.7

The current business plan maintains a total FTE count of 37.3 versus the 2017 OEB approved headcount of 41. The general basis for the reduction is the following:

- Reduction of four FTE's in Billing and Collecting due to:
    - Reduction of one CSR
    - Reduction of a billing management position
    - Reduction of a billing clerk
    - Reduction of Director Oversight

- Engineering: Increase of 1.6 FTEs due to:
    - The addition of the Engineering and Operations Assistant to manage growth coupled with the introduction of Engineering Supervision

- Metering: Decrease of one FTE due to:
    - Outsourcing non-payment disconnect processing and meter-resealing activities

- System Control: Net increase of 0.6 FTEs
    - WHESC's allocation of system control room operators from the shared services arrangement added 0.6 FTEs from 2017 COS levels. The arrangement provides WHESC with 24 x 7 coverage in comparison to the 8 hours x 5 days model used in 2017.

- Administration: Decrease of one FTE
    - Upon retirement of the President and CEO at the end of 2016, an internal administrative staff member moved into that role, reducing the department compliment to two.

This results in a net reduction from 2017 COS levels of 3.7.

By leveraging shared services and third-party services, WHESC is better positioned to manage costs while increasing service level and operational efficiency. For example, the control room services arrangement allows WHESC and EPLC to leverage a 24 x 7 coverage model with minimal incremental cost. Implementation of a 24x7 system control operation by either LDC individually would not be cost feasible.

Table 4.1 contains the total full time equivalent ("FTEs") for the 2025 Five-Year Plan. The head count is planned to remain consistent through to 2029.

2025 Business Plan Deliverables

- **Maintain the total FTE count at 37.3 by continuing to pursue shared services opportunities to manage OM&A expenditures.**

4.2 Collective Agreement

The current four-year collective agreement expires on March 31, 2026 and includes increases of 2.2% (2022), 2.2% (2023), 2.2% (2024) and 2.2% (2025).

During the first quarter of 2026, WHESC will review existing wage rates for unionized positions at LDCs in the Niagara Peninsula and within GridSmart City. The review will also include recent contract settlements within the industry.

Although WHESC needs to maintain competitive rates within the LDC sector, cost control remains a major focus of intervenors and the OEB. Annual wage increases of 3.0% have been assumed during the forecast period.

2025 Business Plan Deliverables

- **A new collective agreement which allows WHESC to maintain competitive wage rates that will attract and retain personnel with the appropriate skill set. The new agreement should also consider impacts on distribution rates in comparison to the increases to revenues provided through the IRM rate setting process.**

5.1 Income Statement

Table 5.1 below summarizes the assumptions made to revenue, expenses, interest, and amortization throughout this plan.

Table 5.1: Income Statement

INCOME STATEMENT							
2025 FIVE YEAR PLAN							
	2017	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
	Full Year	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**	**Full Year**
	COS	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**	**Plan**
Revenues							
Total Distribution Revenue	9,772,399	12,449,513	13,002,433	13,178,072	13,604,941	14,042,464	14,491,470
Total Other Operating Revenue-Distribution	441,760	685,971	638,167	650,731	656,071	661,478	667,018
Miscellaneous Operating Non-Distribution	0	23,385	0	0	0	0	0
Total Operating Revenue	**10,214,159**	**13,158,869**	**13,640,600**	**13,828,803**	**14,261,012**	**14,703,941**	**15,158,488**
Expenses							
Operations & Maintenance	3,314,316	4,175,132	4,705,050	4,889,369	5,063,281	5,182,064	5,336,253
Customer Service	1,611,467	1,707,242	1,835,009	1,896,032	1,957,722	2,015,687	2,079,400
Administration	1,874,217	2,223,426	2,283,599	2,283,313	2,378,143	2,435,589	2,526,754
Amortization	1,415,729	1,937,442	1,891,408	1,985,159	2,091,738	2,190,438	2,279,657
Interest Expense	725,013	700,615	912,604	842,468	907,162	994,460	1,076,245
Earnings Before Taxes	**1,273,417**	**2,415,011**	**2,012,929**	**1,932,462**	**1,862,966**	**1,885,704**	**1,860,179**
Payments in Lieu of Taxes	91,097	473,258	315,602	249,397	215,708	208,119	206,293
Net Earnings	**1,182,320**	**1,941,753**	**1,697,327**	**1,683,065**	**1,647,258**	**1,677,585**	**1,653,886**

5.2 Balance Sheet

Table 5.2 provides a detailed Balance Sheet for the 2025 Five-Year Plan. Assumptions contained in the Five-Year Plan include planned income, capital spending, depreciation, and regulatory liability balances to be refunded to customers by April 2026. The Balance Sheet also includes additional long-term debt that will be acquired annually beginning in 2025 at approximately $2.5M per year. The planned acquisition of debt still results in WHESC operating below the deemed debt/equity structure of 60%/40% throughout the five-year plan period.

The forecasted balance shows strong growth in property plant & equipment (28.3% over five years) as capital spending continues to exceed depreciation levels over the business plan period.

Table 5.2: Balance Sheet

BALANCE SHEET						
2025 FIVE YEAR PLAN						
	2024	2025	2026	2027	2028	2029
	Plan	Plan	Plan	Plan	Plan	Plan
ASSETS						
Current Assets						
Cash & Cash Equivalents	2,233,042	2,043,605	791,681	553,483	773,308	829,144
Accounts Receivable	4,191,557	4,317,304	4,446,823	4,580,228	4,717,635	4,859,164
Unbilled Revenues	5,236,615	5,393,713	5,555,525	5,722,191	5,893,856	6,070,672
Inventories	959,846	994,436	1,030,063	1,066,760	1,104,557	1,143,488
Prepaid and Other Current Assets	564,393	581,325	598,764	616,727	635,229	654,286
AR Due from Related Parties	98,486	101,440	104,484	107,618	110,847	114,172
Total Current Assets	**13,283,939**	**13,431,823**	**12,527,340**	**12,647,007**	**13,235,432**	**13,670,926**
Non-Current Assets						
Property, Plant & Equipment	46,381,206	49,362,534	52,255,349	54,781,181	57,174,603	59,500,889
Intangible Assets	69,461	28,983	15,308	4,606	593	235
Derivative Instrument	1,010,926	1,010,926	1,010,926	1,010,926	1,010,926	1,010,926
Total Non-Current Assets	**47,461,593**	**50,402,443**	**53,281,584**	**55,796,713**	**58,186,123**	**60,512,050**
Total Assets	**60,745,533**	**63,834,266**	**65,808,923**	**68,443,720**	**71,421,555**	**74,182,976**
Debit Regulatory Balances	2,077,718	1,562,682	1,465,315	1,465,315	1,465,316	1,465,314
Total Assets and Regulatory Balances	**62,823,251**	**65,396,948**	**67,274,238**	**69,909,035**	**72,886,871**	**75,648,290**
LIABILITIES						
Current Liabilities						
Accounts Payable and Accrued Liabilities	- 6,319,814	- 6,509,408	- 6,704,691	- 6,905,831	- 7,113,006	- 7,326,396
Customer Deposits Current	- 2,936,251	- 2,936,251	- 2,936,251	- 2,936,251	- 2,936,251	- 2,936,251
Current Portion Long-Term Debt	- 350,460	- 465,452	- 543,735	- 646,426	- 774,433	- 908,619
Other Current Liabilities	- 0	- 0	- 0	- 0	- 0	- 0
Total Current Liabilities	**- 9,606,526**	**- 9,911,112**	**- 10,184,677**	**- 10,488,509**	**- 10,823,690**	**- 11,171,267**
Non-Current Liabilities						
Long-Term Debt	- 19,485,372	- 21,419,866	- 22,316,100	- 23,589,631	- 25,215,145	- 26,706,473
Post-employment Benefits	- 993,751	- 993,751	- 993,751	- 993,751	- 993,751	- 993,751
Deferred PILs - Long term	- 1,259,202	- 1,259,202	- 1,259,202	- 1,259,202	- 1,259,202	- 1,259,202
Derivative Instrument	-	-	-	-	-	-
Deferred Revenue	- 5,494,188	- 5,643,498	- 5,773,504	- 5,883,680	- 5,973,235	- 6,041,864
Total Non-Current Liabilities	**- 27,232,513**	**- 29,316,318**	**- 30,342,557**	**- 31,726,264**	**- 33,441,333**	**- 35,001,289**
Total Liabilities	**- 36,839,038**	**- 39,227,430**	**- 40,527,234**	**- 42,214,773**	**- 44,265,023**	**- 46,172,557**
EQUITY						
Share Capital	- 12,953,180	- 12,953,180	- 12,953,180	- 12,953,180	- 12,953,180	- 12,953,180
Retained Earnings	- 10,101,989	- 11,198,452	- 12,231,518	- 13,178,775	- 14,106,361	- 14,960,246
Accumulated Other Comprehensive Income	- 897,759	- 897,759	- 897,759	- 897,759	- 897,759	- 897,759
Total Equity	**- 23,952,928**	**- 25,049,392**	**- 26,082,457**	**- 27,029,714**	**- 27,957,300**	**- 28,811,185**
Total Liabilities & Equity	**- 60,791,966**	**- 64,276,821**	**- 66,609,691**	**- 69,244,488**	**- 72,222,323**	**- 74,983,742**
Credit Regulatory Balances	- 2,031,285	- 1,120,127	- 664,548	- 664,548	- 664,548	- 664,548
Total Liabilities, Equity & Regulatory Balances	**- 62,823,251**	**- 65,396,948**	**- 67,274,238**	**- 69,909,035**	**- 72,886,871**	**- 75,648,290**

2025 Business Plan Deliverables

- **Property, Plant & Equipment growth of 28% increasing shareholder value**
- **Net Income – Fund the difference between capital spending and depreciation such that the deemed OEB debt/equity structure of 60%/40% is not exceeded in the business plan period.**
- **Equity growth at 20%**
- **2029 Planned Debt to Equity Ratio 49/51% (OEB 60/40%)**

5.3 Financial Targets

A key component of the 2025 Five-Year Plan is to determine the rate impacts of capital spending and increased operating expenses compared to revenue growth during the IRM rate periods beyond 2025. For the purposes of this business plan, distribution rates were increased by 2.00% per year. Table 5.3 below analyzes whether or not the IRM rate increases will be sufficient enough to cover expenses, depreciation, and return on capital (interest and equity).

Table 5.3: Planned versus Deemed Net Income

	2017	2024	2025	2026	2027	2028	2029
	COS	Plan	Plan	Plan	Plan	Plan	Plan
Cost of Power	48,709,328	44,451,498	45,016,203	45,916,528	46,834,858	47,771,555	48,726,986
OM&A	6,800,000	8,090,780	8,823,658	9,068,714	9,399,147	9,633,339	9,942,408
Total Working Capital Base	55,509,328	52,542,277	53,839,862	54,985,242	56,234,005	57,404,895	58,669,394
Working capital allowance per COS	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital Allowance	4,163,200	3,940,671	4,037,990	4,123,893	4,217,550	4,305,367	4,400,205
Average Fixed Assets	29,501,969	39,630,648	42,011,539	44,781,789	47,345,147	49,777,111	52,062,677
Total Rate Base	**33,665,168**	**43,571,319**	**46,049,529**	**48,905,682**	**51,562,697**	**54,082,478**	**56,462,881**
Deemed Equity	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	13,466,067	**17,428,528**	**18,419,811**	**19,562,273**	**20,625,079**	**21,632,991**	**22,585,152**
Deemed rate of return	**8.78%**	**8.78%**	**9.21%**	**9.21%**	**9.21%**	**9.21%**	**9.21%**
Deemed Regulated Income	**1,182,321**	**1,530,225**	**1,696,465**	**1,801,685**	**1,899,570**	**1,992,399**	**2,080,093**
Net Income per Financial Statements		**1,941,753**	**1,696,464**	**1,683,065**	**1,647,258**	**1,677,585**	**1,653,886**
Adjustment Items:							
Non-Rate Regulated items		-11,012	0	0	0	0	0
Non-recoverable donations		15,021	0	0	0	0	0
Net interest/carring charges from DVAs		65,000	0	55,000	50,000	50,000	50,000
Interest adjustment for deemed debt		-302,737	0	-181,246	-164,182	-126,795	-92,160
Tax adjustment		61,930	0	33,453	30,257	20,350	11,172
Achieved Regulated Net Income (OEB)		**1,769,956**	**1,696,465**	**1,590,273**	**1,563,333**	**1,621,140**	**1,622,898**
Achieved Rate of Return		**10.16%**	**9.21%**	**8.13%**	**7.58%**	**7.49%**	**7.19%**

The 2025 COS Rate Application includes a rate base of $46,049,529 and a regulated net income of $1,696,465. Table 5. above shows WHESC's rate base increasing to $56,462,881 in 2029. As a result of the increase in rate base, projected Deemed Net Income will rise to $2,080,093 in 2029. Actual net income per the Financial Statements is not planned to exceed Deemed Regulated Net Income over the period 2025 to 2029.

WHESC continually monitors its performance against industry standards and performance targets. Table 5. below compares WHESC's planned OM&A and Capital costs to the target costs based on Pacific Economics Group (PEG) benchmarking parameters. PEG calculates the expected increase in costs based on the annual increase in inflation and customer growth. WHESC's Five-

Year Plan produces total OM&A and Capital costs that are lower than what is expected under PEG analysis using escalators.

Table 5.4: Cost Benchmarking Results

Summary of Cost Benchmarking Results

Welland Hydro-Electric System Corp.

	2020 (History)	2021 (History)	2022 (History)	2023 (History)	2024 (Bridge)	2025 (Test Year)
Cost Benchmarking Summary						
Actual Total Cost	11,874,844	12,154,000	12,993,461	14,445,324	15,755,141	17,198,605
Predicted Total Cost	16,082,567	16,836,832	18,568,263	21,309,905	22,430,601	24,337,040
Difference	(4,207,723)	(4,682,832)	(5,574,802)	(6,864,581)	(6,675,460)	(7,138,435)
Percentage Difference (Cost Performance)	**-30.3%**	**-32.6%**	**-35.7%**	**-38.88%**	**-35.33%**	**-34.72%**
Three-Year Average Performance			-32.9%	-35.72%	-36.64%	-36.31%
Stretch Factor Cohort						
Annual Result	1	1	1	1	1	1
Three Year Average			1	1	1	1

2025 Business Plan Deliverables

- Rate Base increase from $43,571,319 in 2024 to $56,462,881 in 2029 (29.6%)
- Continue to monitor performance against industry benchmarks and performance targets to ensure WHESC remains in Cohort I (0.00)
- Ensure total OM&A and capital cost remains below expected values based on escalators

Appendix 1-B: Executive Certification

Certification of Evidence

I hereby certify that, to the best of my knowledge, the evidence filed in this Application, including the models and appendices, is accurate, consistent and complete.

This application and evidence filed in support of this application does not include any personal information.

I also certify that, to the best of my knowledge, Welland Hydro has the appropriate processes and internal controls in place for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition.

Certified by:

Kevin Carver

____

Kevin Carver, P.Eng., ME

President and CEO
Welland Hydro-Electric System Corp.
950 East Main Street
Welland, ON L3B 5P6

T: 905-732-1381 Ext 223

kcarver@wellandhydro.com

Date:

August 23, 2024

Appendix 1-C: OEB 2023 Scorecard

Scorecard - Welland Hydro-Electric System Corp.

8/12/2024

										Target	
Performance Outcomes	**Performance Categories**	**Measures**		**2019**	**2020**	**2021**	**2022**	**2023**	**Trend**	**Industry**	**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		94.82%	94.52%	99.68%	99.61%	95.53%	⬆	90.00%	
		Scheduled Appointments Met On Time		93.16%	98.28%	97.88%	93.99%	94.88%	⬇	90.00%	
		Telephone Calls Answered On Time		88.90%	86.15%	83.07%	77.88%	76.33%	⬇	65.00%	
	Customer Satisfaction	First Contact Resolution		80	77	99.89%	99.81%	99.70			
		Billing Accuracy		99.99%	99.99%	99.91%	99.88%	99.97%	⬇	98.00%	
		Customer Satisfaction Survey Results		96	96	96%	98%	98%			
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		83.00%	83.00%	83.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	➡		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	2	0	➡		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.402	0.000	➡		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.71	2.36	1.52	1.13	1.33	⬇		1.78
		Average Number of Times that Power to a Customer is Interrupted [2]		2.41	2.02	1.35	1.14	1.08	⬇		1.81
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	Completec	Completed	Completed			
	Cost Control	Efficiency Assessment		2	1	1	1	1			
		Total Cost per Customer [3]		$512	$494	$494	$518	$561			
		Total Cost per Km of Line [3]		$24,714	$24,038	$24,455	$26,144	$29,198			
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)		1.44	1.73	1.58	1.32	1.41			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.83	0.97	0.91	0.86	0.92			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.78%	8.78%	8.78%	8.78%	8.78%			
			Achieved	10.44%	9.36%	10.72%	11.71%	12.97%			

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

Appendix 1-D: WHESC 2023 Audited Financial Statements

Financial Statements of

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

And Independent Auditor's Report thereon

Year ended December 31, 2022
(Expressed in thousands of dollars)

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Table of Contents

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton ON L8P 4W7
Canada
Tel 905-523-8200
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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Welland Hydro-Electric System Corp.

Opinion

We have audited the financial statements of Welland Hydro-Electric System Corp. (the Entity), which comprise:

- the statement of financial position as at December 31, 2022
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditor's Responsibilities for the Audit of the Financial Statements***" section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of non-financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada

April 12, 2023

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Financial Position

December 31, 2022, with comparative information for 2021
(in thousands of dollars)

	Notes	2022	2021
Assets			
Current assets:			
Cash and cash equivalents	4	$ 706	$ 2,925
Accounts receivable	5	3,382	2,914
Unbilled revenue		4,601	4,620
Materials and supplies	6	877	648
Prepaid expenses		458	430
Due from related parties	20	142	85
Total current assets		10,166	11,622
Non-current assets:			
Property, plant and equipment	7	40,577	38,274
Intangible assets	8	305	438
Derivative instrument	22	1,508	–
Total non-current assets		42,390	38,712
Total assets		52,556	50,334
Regulatory balance	10	2,967	1,193
Total assets and regulatory balances		$ 55,523	$ 51,527

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Financial Position (continued)

December 31, 2022, with comparative information for 2021
(in thousands of dollars)

	Notes	2022	2021
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	11	$ 5,151	$ 5,153
Customer deposits		2,158	1,804
Other liabilities		287	253
Current portion of long-term debt	12	213	209
Total current liabilities		7,809	7,419
Non-current liabilities:			
Long-term debt	12	$ 17,755	$ 17,968
Post-employment benefits	13	913	1,268
Deferred revenue		3,439	2,894
Deferred tax liabilities	9	869	301
Derivative instrument	22	–	277
Total non-current liabilities		22,976	22,708
Total liabilities		30,785	30,127
Shareholders' equity:			
Share capital	14	12,953	12,953
Retained earnings		7,988	7,023
Accumulated other comprehensive income (loss)		1,395	(390)
Total equity		22,336	19,586
Total liabilities and equity		53,121	49,713
Regulatory balances	10	2,402	1,814
Total liabilities and shareholder's equity		$ 55,523	$ 51,527

See accompanying notes to financial statements.

Approved by the Board of Directors:

Director

Director

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Comprehensive Income

Year ended December 31, 2022, with comparative information for 2021
(in thousands of dollars)

	Notes		2022		2021
Revenue					
Sale of energy	15	$	46,109	$	45,403
Distribution	15		11,728		11,413
Other	15		131		126
			57,968		56,942
Operating and administrative expenses:					
Cost of power purchased			47,022		45,827
Employee salaries and benefits	16		3,424		3,745
Operating expenses	17		3,731		3,094
Depreciation and amortization			1,940		1,829
			56,117		54,495
Income from operating activities			1,851		2,447
Finance income	18		61		25
Finance cost	18		516		503
Income before income taxes			1,396		1,969
Income tax expense (recovery)	9		617		(163)
Net income for the year			779		2,132
Net movement in regulatory balances, net of tax	10		1,186		(209)
Net income for the year and net movement in regulatory balances			1,965		1,923
Other comprehensive income, net of tax:					
Cash flow hedges – effect portion of changes in FV	22		1,785		1,032
Total comprehensive income for the year		$	3,750	$	2,955

See accompanying notes to financial statements.

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Changes in Equity

Year ended December 31, 2022, with comparative information for 2021

		Share capital		Retained earnings		Accumulated other comprehensive income (loss)		Total
Balance at January 1, 2021	$	12,953	$	6,100	$	(1,422)	$	17,631
Net income and net movement in regulatory balances		–		1,923		–		1,923
Dividends		–		(1,000)		–		(1,000)
Other comprehensive income		–		–		1,032		1,032
Balance at December 31, 2021	$	12,953	$	7,023	$	(390)	$	19,586
Balance at January 1, 2022	$	12,953	$	7,023	$	(390)	$	19,586
Net income and net movement in regulatory balances		–		1,965		–		1,965
Dividends		–		(1,000)		–		(1,000)
Other comprehensive income		–		–		1,785		1,785
Balance at December 31, 2022	$	12,953	$	7,988	$	1,395	$	22,336

See accompanying notes to financial statements.

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Cash Flows

Year ended December 31, 2022, with comparative information for 2021

	2022	2021
Cash provided by (used in):		
Operating activities:		
Total comprehensive income for the year	$ 3,750	$ 2,955
Items not involving cash:		
Depreciation and amortization	1,940	1,829
Amortization of deferred revenue	(102)	(84)
Post-employment benefits	(355)	(140)
Loss on disposal of property, plant and equipment	2	38
Net finance costs	455	478
Income tax expense (recovery)	617	(163)
Derivative instrument	(1,785)	(1,032)
	4,522	3,881
Changes in non-cash operating working capital		
Accounts receivable	(468)	122
Due to/from related parties	(57)	14
Unbilled revenue	19	1,592
Materials and supplies	(229)	(158)
Prepaid expenses	(28)	8
Accounts payable and accrued liabilities	112	(119)
Customer deposits	354	86
Other liabilities	34	6
	(263)	1,551
Regulatory balances	(1,186)	209
Income tax paid	(163)	(206)
Income tax received	–	–
Interest paid	(516)	(503)
Interest received	61	25
Contributions received from customers	647	727
	3,102	5,684
Investing activities:		
Purchase of property, plant and equipment	(4,107)	(3,998)
Proceeds on disposal of property, plant and equipment	10	12
Purchase of intangible assets	(15)	(29)
	(4,112)	(4,015)
Financing activities:		
Dividends paid	(1,000)	(1,000)
Proceeds from long-term debt	–	–
Repayment of long-term debt	(209)	(205)
	(1,209)	(1,205)
Change in cash and cash equivalents	(2,219)	464
Cash and cash equivalents, beginning of year	2,925	2,461
Cash and cash equivalents, end of year	$ 706	$ 2,925

See accompanying notes to financial statements.

1. Reporting entity:

Welland Hydro-Electric System Corp. (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the City of Welland. The address of the Corporation’s registered office is 950 East Main Street, Welland Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the City of Welland. The Corporation is wholly owned by Welland Hydro-Electric Holding Corp. and the ultimate parent company is the City of Welland.

The financial statements are for the Corporation as at and for the year ended December 31, 2022.

2. Basis of presentation:

(a) Statement of compliance:

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

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on (date).

(c) Basis of measurement:

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

(d) Functional and presentation currency:

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

2. Basis of presentation (continued):

(e) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

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

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

(b) Note 3(c) – measurement of unbilled revenue

(c) Note 5 – receivables and allowance for doubtful accounts

(d) Note 9 – deferred tax assets and liabilities

(e) Note 10 – recognition and measurement of regulatory balances

(f) Note 13 – recognition and measurement of employee future benefits

(g) Note 19 – recognition and measurement of provisions and contingencies

(h) Note 22 – measurement of fair value of derivatives

2. Basis of presentation (continued):

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

(ii) Judgements:

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

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

(b) Notes 3 (j), 10 – recognition of regulatory balances

(f) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, and among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate setting:

Distribution revenue:

For the distribution revenue included in revenues, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

2. Basis of presentation (continued):

(f) Rate regulation (continued):

Rate setting (continued):

Distribution revenue (continued):

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in 2016 for rates effective May 1, 2017. The OEB has approved the Corporation's request to defer the next COS application to rates effective May 1, 2025 and the Corporation will continue to file annual IRM applications until that time. The GDP IPI-FDD used for 2022 rates was 3.3%, the Corporation's productivity factor was 0.0% and the stretch factor was 0.0%, resulting in a net adjustment of 3.3% to the previous year's rates.

Electricity rates:

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity.

In 2020, the OEB adjusted the Regulated Price Plan (RPP) prices in March and June in response to the Government issued Emergency Orders under the Emergency Management and Civil Protection Act to assist Ontarians who were forced to stay home due to the COVID-19 pandemic. Throughout 2021 and into January 2022, the OEB continued to amend RPP prices as necessary due to the ongoing COVID-19 pandemic, including forgoing the RPP semi-annual price increase for November 1, 2021. Effective January 1, 2022, the OEB implemented an annual RPP price increase effective November 1st of each year. This directive replaced the previous semi-annual price increase structure of May 1st and November 1st. RPP prices were amended for all customers under RPP pricing effective November 1, 2022.
All remaining consumers pay the market price for electricity.

The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

2. Basis of presentation (continued):

(f) Rate regulation (continued):

Rate setting (continued):

Retail transmission rates:

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

Wholesale market service rates:

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

3. Significant account policies:

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

(a) Financial instruments:

Financial assets and financial liabilities are recognized in the statements of financial position when the Corporation becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognized immediately in profit or loss.

All regular way purchases or sales of financial assets are recognized and derecognized on a trade date basis. Regular way purchases or sales are purchases or sales of financial assets that require delivery of assets within the time frame established by regulation or convention in the marketplace. The Corporation recognizes all financial assets subsequently in their entirety at amortized cost except for derivative instruments.

3. Significant account policies (continued):

(a) Financial instruments (continued):

(i) Classification and measurement of financial instruments:

The measurement and classification categories of financial assets in accordance with IFRS 9 at are outlined in the below table:

Financial asset/liability	IFRS 9
Cash and cash equivalents	Amortized cost
Accounts receivable	Amortized cost
Due from related parties	Amortized cost
Accounts payable and accrued liabilities	Amortized cost
Derivative instruments	Fair value through other comprehensive income
Customer deposits	Amortized cost
Long-term debt	Amortized cost

There were no changes to the classification and measurement of the balance sheet other than derivative instruments being added in the prior year and a new derivative instrument in the current year based on interest rate swaps entered into by the Corporation. The swaps are discussed in this note under financial liabilities.

(ii) Classification of financial assets:

Debt instruments that meet the following conditions are measured subsequently at amortized cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

(iii) Derecognition of financial assets:

The Corporation derecognizes a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Corporation neither transfers nor retains substantially all the risks and rewards of ownership and continues to control the transferred asset, the Corporation recognizes its retained interest in the asset and an associated liability for amounts it may have to pay.

On derecognition of a financial asset measured at amortized cost, the difference between the asset's carrying amount and the sum of the consideration received and receivable is recognized in profit or loss.

3. Significant account policies (continued):

(a) Financial instruments (continued):

(iv) Financial liabilities:

All financial liabilities other than derivative instruments are measured subsequently at amortized cost using the effective interest method.

The effective interest method is a method of calculating the amortized cost of a financial liability and of allocating interest expense over the relevant period.

The effective interest rate is the rate that exactly discounts estimated future cash payments (including all fees and points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial liability, or (where appropriate) a shorter period, to the amortized cost of a financial liability.

The Corporation entered into interest rate swap agreements to manage its exposure to interest rate fluctuations related to the $3,500 and $13,500 loans presented in Note 12. Derivatives are recognized initially at fair value at the date the contract is entered into and are subsequently remeasured to their fair value at each reporting date. The resulting gain or loss is recognized through other comprehensive income immediately unless the derivative is designated and effective as a hedging instrument, in which event the timing of the recognition in other comprehensive income depends on the nature of the hedge relationship. The Corporation did not designate the instrument as a hedging instrument. Instead, the interest rate swap is marked to market at December 31, 2022 and the gain or loss is recognized in other comprehensive loss as Cash flow hedges-effective portion of changes in fair value.

(v) Derecognition of financial liabilities:

The Corporation derecognizes financial liabilities when, and only when, the Corporation's obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

When the Corporation exchanges with the existing lender one debt instrument into another one with substantially different terms, such exchange is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. Similarly, the Corporation accounts for substantial modification of terms of an existing liability or part of it as an extinguishment of the original financial liability and the recognition of a new liability.

3. Significant account policies (continued):

(b) Cash and cash equivalents:

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

(c) Revenue recognition:

Sale and distribution of electricity:

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Other revenue:

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

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset. Capital contributions received from developers to construct or acquire capital assets for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15.

Government grants and the related performance incentive payments under Conservation Demand Management (“CDM”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received. Performance incentive payments are considered out of scope of IFRS 15 Revenue from Contracts with Customer [“IFRS 15”].

(d) Materials and supplies:

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

3. Significant account policies (continued):

(e) Property plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labor, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

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

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

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

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

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

3. Significant account policies (continued):

(e) Property plant and equipment (continued):

The estimated useful lives are as follows:

Asset	Years
Buildings	40 - 60
Distribution equipment	
Distribution stations	20 - 45
Poles and overhead/underground lines	50
Underground plant	20 - 50
Distribution transformers	40
Distribution meters	15
Other	4 - 60

(f) Intangible assets:

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

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization. Payments to obtain rights to access land ("land rights") are classified as intangible assets.

These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

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

The estimated useful lives are:

Asset	Years
Computer software	5
Land rights	25

3. Significant account policies (continued):

(g) Impairment:

(i) Financial assets measured at amortized cost:

A financial asset is assessed using the lifetime expected credit losses (“ECL”) model to determine whether there is any objective evidence that it is impaired, using the simplified approach. This includes both quantitative and qualitative information and analysis, based on the Corporation’s historical experience, adjusted for forward-looking factors specific to the current credit environment.

The Corporation measures the loss allowance at an amount equal to the lifetime ECL for trade receivables or contract assets that result from transactions that are within the scope of IFRS 15, and do not contain a significant financing component. The Corporation uses a provision matrix to measure the lifetime ECL of accounts receivable from individual customers which accounts for exposures in different customer classes.

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

(ii) Non-financial assets:

The carrying amounts of the Corporation’s non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset’s recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the “cash-generating unit” or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

3. Significant account policies (continued):

(h) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

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

(i) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(j) Regulatory balances:

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

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

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

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

3. Significant account policies (continued):

(k) Post-employment benefits:

Pension plan:

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

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

Post-employment benefits, other than pension:

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

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(l) Finance income and finance costs

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

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

3. Significant account policies (continued):

(m) Income taxes:

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

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

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

Rate regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates.

4. Cash and cash equivalents:

	2022	2021
Bank balances	$ 706	$ 2,925

5. Accounts receivable:

	2022	2021
Trade receivables	$ 3,546	$ 2,950
Less loss allowance	(278)	(248)
	3,268	2,702
Other trade receivables	5	2
Billable work	109	210
	$ 3,382	$ 2,914

6. Materials and supplies:

Amount recovered pertaining to materials and supplies in 2022 was $19 (2021 - $6).

7. Property, plant and equipment:

	Land and building	Distribution equipment	Other fixed assets	Construction in progress	Total
Cost or deemed cost					
Balance at January 1, 2022	$ 2,299	$ 41,396	$ 5,278	$ 48	$ 49,021
Additions	–	3,646	443	18	4,107
Transfers	–	33	5	(38)	–
Disposals/retirements	–	(28)	–	–	(28)
Balance at December 31, 2022	$ 2,299	$ 45,047	$ 5,726	$ 28	$ 53,100
Accumulated depreciation					
Balance at January 1, 2022	$ (645)	$ (8,191)	$ (1,911)	$ –	$ (10,747)
Depreciation	(95)	(1,346)	(351)	–	(1,792)
Disposals/retirements	–	16	–	–	16
Balance at December 31, 2022	(740)	(9,521)	(2,262)	–	(12,523)
Carrying amount at December 31, 2022	$ 1,559	$ 35,526	$ 3,464	$ 28	$ 40,577
Cost or deemed cost					
Balance at January 1, 2021	$ 2,294	$ 38,161	$ 4,687	$ 6	$ 45,148
Additions	5	3,298	647	48	3,998
Transfers	–	6	–	(6)	–
Disposals/retirements	–	(69)	(56)	–	(125)
Balance at December 31, 2021	$ 2,299	$ 41,396	$ 5,278	$ 48	$ 49,021
Accumulated depreciation					
Balance at January 1, 2021	$ (548)	$ (6,950)	$ (1,657)	$ –	$ (9,155)
Depreciation	(97)	(1,260)	(310)	–	(1,667)
Disposals/retirements	–	19	56	–	75
Balance at December 31, 2021	(645)	(8,191)	(1,911)	–	(10,747)
Carrying amount at December 31, 2021	$ 1,654	$ 33,205	$ 3,367	$ 48	$ 38,274

At December 31, 2022 all property, plant and equipment are subject to a general security agreement.

Property, plant and equipment and intangible asset purchase commitments outstanding as at December 31, 2021 was $762 (2021 - $999).

8. Intangible assets:

		Computer software		Land rights		Construction in progress		Total
Cost or deemed cost								
Balance at January 1, 2022	$	853	$	10	$	18	$	881
Additions		8		–		7		15
Transfers		–		–		–		–
Disposals/retirements		–		–		–		–
Balance at December 31, 2022	$	861	$	10	$	25	$	896
Accumulated depreciation								
Balance at January 1, 2022	$	(438)	$	(5)	$	–	$	(443)
Depreciation		(147)		(1)		–		(148)
Disposals/retirements		–		–		–		–
Balance at December 31, 2022		(585)		(6)		–		(591)
Net book value at December 31, 2022	$	276	$	4	$	25	$	305
Cost or deemed cost								
Balance at January 1, 2021	$	842	$	10	$	–	$	852
Additions		11		–		18		29
Transfers		–		–		–		–
Disposals/retirements		–		–		–		–
Balance at December 31, 2021		853		10		18		881
Accumulated depreciation								
Balance at January 1, 2021		(277)		(5)		–		(282)
Depreciation		(161)		–		–		(161)
Disposals/retirements		–		–		–		–
Balance at December 31, 2021		(438)		(5)		–		(443)
Net book value at December 31, 2021	$	415	$	5	$	18	$	438

9. Income tax expense:

		2022		2021
Current tax expense:				
Current year expense	$	48	$	232
Deferred tax expense (recovery):				
Changes in recognized deductible temporary differences		569		(395)
Income tax expense (recovery)	$	617	$	(163)

Reconciliation of effective tax rate:

		2022		2021
Income before income taxes	$	1,396	$	1,969
Canada and Ontario statutory income tax rates		26.5%		26.5%
Expected tax provision on income at statutory rates	$	370	$	522
Decrease in income taxes resulting from:				
Corporate minimum tax		(195)		(124)
Other and prior period adjustments		442		(561)
Income tax expense (recovery)	$	617	$	(163)

Significant components of the Corporation’s deferred tax (liability) asset balance:

		2022		2021
Deferred tax (liabilities) assets:				
Property, plant and equipment	$	(1,238)	$	(921)
Regulatory balances		(68)		160
Post-employment benefits		242		336
Corporate minimum tax		195		124
	$	(869)	$	(301)

10. Regulatory balances:

	January 1, 2022	Additions	Recovery/ additions	December 31, 2022	Remaining Recovery/ reversal year
Regulatory deferral account debit balance:					
Group 1 deferred accounts	$ 357	$ 1,152	$ 174	$ 1,683	–
Regulatory transition to IFRS	35	1	–	36	–
Regulatory settlement accounts	84	10	–	94	–
Other regulatory accounts	133	26	–	159	–
Income tax	584	–	411	995	–
	$ 1,193	$ 1,189	$ 585	$ 2,967	

	January 1, 2021	Additions	Recovery/ additions	December 31, 2021	Remaining Recovery/ reversal year
Regulatory deferral account debit balance:					
Group 1 deferred accounts	$ 113	$ 323	$ (79)	$ 357	–
Regulatory transition to IFRS	35	–	–	35	–
Regulatory settlement accounts	84	–	–	84	0.33
Other regulatory accounts	183	(50)	–	133	–
Income tax	931	–	(347)	584	–
	$ 1,346	$ 273	$ (426)	$ 1,193	

	January 1, 2022	Additions	Recovery/ reversals	December 31, 2022	Remaining Recovery/ reversal year
Regulatory deferral account credit balances:					
Group 1 deferred accounts	$ (736)	$ (275)	$ 211	$ (800)	–
Regulatory settlement account	(125)	(35)	–	(160)	–
Other regulatory accounts	(953)	(489)	–	(1,442)	–
Income tax	–	–	–	–	–
	$ (1,814)	$ (799)	$ 211	$ (2,402)	

10. Regulatory balances (continued):

	January 1, 2021	Additions	Recovery/ reversals	December 31, 2021	Remaining Recovery/ reversal year
Regulatory deferral account credit balances:					
Group 1 deferred accounts	$ (802)	$ (321)	$ 387	$ (736)	–
Regulatory settlement account	(350)	225	–	(125)	–
Other regulatory accounts	(608)	(345)	–	(953)	–
Income tax	–	–	–	–	–
	$ (1,760)	$ (441)	$ 387	$ (1,814)	–

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. An application was made and approved by the OEB to recover $51 of the Group 1 deferral accounts over a one-year period beginning May 1, 2023. The approved account balance will be moved to the regulatory settlement account. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2022 the rate ranged from 0.57% to 3.87%.

11. Accounts payable and accrued liabilities:

	2022	2021
Accounts payable – energy purchases	$ 3,557	$ 3,504
Payroll payable	171	151
Other	1,423	1,498
	$ 5,151	$ 5,153

12. Long-term debt:

	2022	2021
Notes payable	$ 17,968	$ 18,177
Current portion	(213)	(209)
	$ 17,755	$ 17,968

Notes payable is comprised of a $1,500 interest only loan with TD Bank which bears interest at 3.62%, a $13,500 interest only swap agreement with TD Bank which bears interest at 2.805% and a $3,500 principal and interest rate swap agreement with TD Bank which bears interest at 1.972%. The loans are due January 2029, December 2029 and May 2035 respectively.

13. Post-employment benefits:

(a) OMERS pension plan:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2022, the Corporation made employer contributions of $352 to OMERS (2021 - $397), of which $57 (2021 - $66) has been capitalized as part of PP&E and the remaining amount of $295 (2021 - $331) has been recognized in profit or loss or charged to billable work.

As at December 31, 2022, OMERS had approximately 559,000 members, of whom 31 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2022, which reported that the plan was 95% funded, with an unfunded liability of $6.7 billion (2021 - $3.1 billion). This unfunded liability is likely to result in future payments by participating employers and members.

13. Post-employment benefits (continued):

(b) Post-employment benefits other than pension:

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

	2022	2021
Reconciliation of the obligation		
Defined benefit obligation, beginning of year	$ 1,268	$ 1,408
Included in profit or loss		
Current service cost	22	25
Interest cost	36	35
Past service cost	–	–
	1,326	1,468
Included in OCI		
Actuarial gains arising from changes in demographic and financial assumptions	(267)	(71)
Benefits paid	(146)	(129)
Defined benefit obligation, end of year	$ 913	$ 1,268

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

	2022	2021
Actuarial assumptions:		
General inflation	2.00%	2.00%
Discount (interest) rate	5.05%	3.00%
Salary levels	3.30%	3.30%
Medical costs	4.70%	4.40%
Dental costs	4.90%	4.70%

A 1% increase in the assumed discount rates would result in the defined benefit obligation decreasing by $89. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $114.

14. Share capital:

		2022		2021
Authorized:				
Unlimited number of common shares				
Issued:				
1,000 common shares	$	12,953	$	12,953

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

The Corporation paid aggregate dividends in the year on common shares of 1000 dollars per share (2021 - $1,000), which amount to total dividends paid in the year of $1,000 (2021 - $1,000).

15. Revenue:

Revenue consists of the following:

		2022		2021
Revenue from contracts with customers:				
Energy sales	$	46,109	$	45,403
Distribution revenue:				
Distribution		11,146		10,746
Third party services		31		27
Pole rentals		230		288
Miscellaneous		321		352
Generation		29		31
Revenue from other sources:				
Contributions received from customers		102		84
Payments related to IESO programs/program administration		–		11
	$	57,968	$	56,942

16. Employee salaries and benefits:

	2022	2021
Salaries, wages and benefits	$ 2,909	$ 3,193
CPP and EI remittances	129	129
Contributions to OMERS	282	319
Post-employment benefit plan	104	104
	$ 3,424	$ 3,745

17. Operating expenses:

	2022	2021
Operations and maintenance	$ 2,030	$ 1,649
Customer service and billing	881	631
Administrative, finance, and IT	820	814
	$ 3,731	$ 3,094

18. Finance income and costs:

	2022	2021
Finance income:		
Interest income on bank deposits	$ 61	$ 25
Finance costs:		
Interest expense on long-term debt	494	497
Interest expense on customer deposits	14	5
Interest expense - other	8	1
	516	503
Net finance costs recognized in profit or loss	$ 455	$ 478

19. Commitments and contingencies:

Independent Electricity System Operator:

As of May 1, 2002 in order for the Corporation to obtain the electricity it requires to distribute to its customers, the Corporation was required to provide security to the Independent Electricity System Operator (IESO) based on its usage. The security obtained was a letter of credit from a financial institution, which requires an interest coverage ratio of more than 1.5 and a debt capitalization ratio of less than 0.6. The letter is in the amount of $2,539 and incurs interest at 0.6% annually.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2022, no assessments have been made.

20. Related party transactions:

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Welland Hydro-Electric Holding Corp., which in turn is wholly-owned by the City of Welland. The City produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

	2022	2021
City of Welland	$ 142	$ 85

20. Related party transactions (continued):

(c) Transactions with parent (Welland Hydro-Electric Holding Corp.) and affiliates:

The following amounts were invoiced to parent and affiliates in the normal course of operations:

	2022	2021
Welland Hydro-Electric Holding Corp.		
Management fees and employee services	$ 11	$ 10
Welland Hydro Energy Services Corp.		
Management fees	9	8
Streetlight/sentinel maintenance and administration	11	9
	$ 31	$ 27

(d) Transactions with ultimate parent (City of Welland)

The Corporation delivers electricity to the City/Town throughout the year for the electricity needs of the City/Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the City/Town, including streetlight maintenance services and sentinel lights.

The following amounts were invoiced to the City of Welland in the normal course of operations:

	2022	2021
Energy (at commercial rates)	$ 1,092	$ 1,075
Rent	28	36
	$ 1,120	$ 1,111

The following expenses were incurred with the City of Welland in the normal course of operations:

	2022	2021
Property taxes and other taxes	$ 59	$ 56
Leases and miscellaneous	12	9
Water	4	4
	$ 75	$ 69

21. Key management personnel:

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

		2022		2021
Director's fees	$	69	$	55
Salaries and other short-term benefits		708		842
	$	777	$	897

22. Financial instruments and risk management:

Fair value disclosure:

The following methods and assumptions were used to estimate the fair value of financial instruments:

- The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments.
- The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.
- Fair value measurement of the derivative instruments is determined on the basis of a discounted cash flow model using inputs that are based on observable market data (i.e. Level 2 inputs). Estimate of future floating-rate cash flows are based on quoted swap rates and future prices. Estimated cash flows are discounted using a yield curve constructed from similar sources and which reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps.

Fair value hierarchy:

Financial instruments recorded at fair value are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);
Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

22. Financial instruments and risk management (continued):

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, market risk (including currency risk, interest rate risk, and price risk), as well as related mitigation strategies, are discussed below.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Welland. No single customer accounts for a balance in excess of 3.5% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the loss allowance at the end of the year at an amount equal to lifetime ECL recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance for impairment at December 31, 2022 is $278 (2021 - $248). An impairment loss of $150 (2021- $10) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2022, approximately $278 (2021 - $248) is considered 60 days past due. The Corporation has over twenty-five thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB and through credit insurance. As at December 31, 2022, the Corporation holds security deposits in the amount of $961 (2021 - $1,055) for electrical accounts.

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation uses derivative instruments to reduce its exposure to interest risk. As at December 31, 2022, the Corporation is committed to a swap transaction on a $13,500 loan with an interest rate of 2.805% maturing December 20, 2029, and a swap transaction on a $3,500 loan with an interest rate of 1.972% maturing May 26, 2035. The mark of the derivatives at December 31, 2022 is $1,508 (2021 – ($277)). The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates. Current deemed interest rates used by the OEB to set distribution rates approximate those included in the Corporation's current distribution rates and would not have a material impact when rates are rebased. There has been no change in the Corporation's exposure to market risks or the manner in which these risks are managed and measured.

22. Financial instruments and risk management (continued):

Financial risks (continued):

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $2.0 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2022, no amounts had been drawn under the Corporation's $2.0 million credit facility.

The majority of accounts payable, as reported on the statement of financial position, are due within 15 to 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2022, shareholder's equity amounts to $22,336 (2021 - $19,586) and long-term debt amounts to $17,968 (2021 - $18,177).

Appendix 1-E: WHESC 2022 Audited Financial Statements

Financial Statements of

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

And Independent Auditor's Report thereon

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

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Table of Contents

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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Welland Hydro-Electric System Corp.

Opinion

We have audited the financial statements of Welland Hydro-Electric System Corp. (the Entity), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards ("IFRS"), as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditor's Responsibilities for the Audit of the Financial Statements***" section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of non- financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada

April 10, 2024

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Financial Position

December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Notes	2023	2022
Assets			
Current assets:			
Cash and cash equivalents	4	$ 3,764	$ 706
Accounts receivable	5	4,069	3,382
Unbilled revenue		5,084	4,601
Materials and supplies	6	926	877
Prepaid expenses		548	458
Due from related parties	20	96	142
Total current assets		14,487	10,166
Non-current assets:			
Property, plant and equipment	7	43,554	40,577
Intangible assets	8	175	305
Derivative instrument	22	1,011	1,508
Total non-current assets		44,740	42,390
Total assets		59,227	52,556
Regulatory balance	10	2,765	2,967
Total assets and regulatory balances		$ 61,992	$ 55,523

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Financial Position (continued)

December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Notes	2023	2022
Liabilities and Shareholder's Equity			
Current liabilities:			
Accounts payable and accrued liabilities	11	$ 6,136	$ 5,151
Customer deposits		3,549	2,158
Other liabilities		291	287
Current portion of long-term debt	12	341	213
Total current liabilities		10,317	7,809
Non-current liabilities:			
Long-term debt	12	$ 19,836	$ 17,755
Post-employment benefits	13	994	913
Deferred revenue		4,544	3,439
Deferred tax liabilities	9	1,259	869
Total non-current liabilities		26,633	22,976
Total liabilities		36,950	30,785
Shareholders' equity:			
Share capital	14	12,953	12,953
Retained earnings		9,160	7,988
Accumulated other comprehensive income		898	1,395
Total equity		23,011	22,336
Total liabilities and equity		59,961	53,121
Regulatory balances	10	2,031	2,402
Total liabilities and shareholder's equity		$ 61,992	$ 55,523

See accompanying notes to financial statements.

Approved by the Board of Directors:

____

Director

____

Director

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Comprehensive Income

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

	Notes	2023	2022
Revenue			
Sale of energy	15	$ 45,116	$ 46,109
Distribution	15	12,334	11,728
Other	15	156	131
		57,606	57,968
Operating and administrative expenses:			
Cost of power purchased		45,027	47,022
Employee salaries and benefits	16	3,437	3,424
Operating expenses	17	3,841	3,731
Depreciation and amortization		2,050	1,940
		54,355	56,117
Income from operating activities		3,251	1,851
Finance income	18	221	61
Finance cost	18	(611)	(516)
Income before income taxes		2,861	1,396
Income tax expense	9	758	617
Net income for the year		2,103	779
Net movement in regulatory balances, net of tax	10	169	1,186
Net income for the year and net movement in regulatory balances		2,272	1,965
Other comprehensive (loss) income, net of tax:			
Cash flow hedges – effect portion of changes in FV	22	(497)	1,785
Total comprehensive income for the year		$ 1,775	$ 3,750

See accompanying notes to financial statements.

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Changes in Equity

Year ended December 31, 2023, with comparative information for 2022

	Share capital	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2022	$ 12,953	$ 7,023	$ (390)	$ 19,586
Net income and net movement in regulatory balances	–	1,965	–	1,965
Dividends	–	(1,000)	–	(1,000)
Other comprehensive income	–	–	1,785	1,785
Balance at December 31, 2022	$ 12,953	$ 7,988	$ 1,395	$ 22,336
Balance at January 1, 2023	$ 12,953	$ 7,988	$ 1,395	$ 22,336
Net income and net movement in regulatory balances	–	2,272	–	2,272
Dividends	–	(1,100)	–	(1,100)
Other comprehensive loss	–	–	(497)	(497)
Balance at December 31, 2023	$ 12,953	$ 9,160	$ 898	$ 23,011

See accompanying notes to financial statements.

WELLAND HYDRO-ELECTRIC SYSTEM CORP.

Statement of Cash Flows

Year ended December 31, 2023, with comparative information for 2022

	2023	2022
Cash provided by (used in):		
Operating activities:		
Total comprehensive income for the year	$ 1,775	$ 3,750
Items not involving cash:		
Depreciation and amortization	2,050	1,940
Amortization of deferred revenue	(128)	(102)
Post-employment benefits	81	(355)
Loss on disposal of property, plant and equipment	2	2
Net finance costs	390	455
Income tax expense	758	617
Derivative instrument	497	(1,785)
	5,425	4,522
Changes in non-cash operating working capital		
Accounts receivable	(669)	(468)
Due to/from related parties	46	(57)
Unbilled revenue	(483)	19
Materials and supplies	(49)	(229)
Prepaid expenses	(90)	(28)
Accounts payable and accrued liabilities	616	112
Customer deposits	1,391	354
Other liabilities	4	34
	766	(263)
Regulatory balances	(169)	(1,186)
Income tax paid	(4)	(163)
Income tax received		–
Interest paid	(606)	(516)
Interest received	203	61
Contributions received from customers	1,233	647
	6,848	3,102
Investing activities:		
Purchase of property, plant and equipment	(4,894)	(4,107)
Proceeds on disposal of property, plant and equipment	5	10
Purchase of intangible assets	(10)	(15)
	(4,899)	(4,112)
Financing activities:		
Dividends paid	(1,100)	(1,000)
Proceeds from long-term debt	2,500	–
Repayment of long-term debt	(291)	(209)
	1,109	(1,209)
Change in cash and cash equivalents	3,058	(2,219)
Cash and cash equivalents, beginning of year	706	2,925
Cash and cash equivalents, end of year	$ 3,764	$ 706

See accompanying notes to financial statements.

1. Reporting entity:

Welland Hydro-Electric System Corp. (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the City of Welland. The address of the Corporation’s registered office is 950 East Main Street, Welland Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the City of Welland. The Corporation is wholly owned by Welland Hydro-Electric Holding Corp. and the ultimate parent company is the City of Welland.

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

2. Basis of presentation:

(a) Statement of compliance:

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

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on (date).

(c) Basis of measurement:

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

(d) Functional and presentation currency:

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

2. Basis of presentation (continued):

(e) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

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

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

(b) Note 3(b) – measurement of unbilled revenue

(c) Note 5 – receivables and allowance for doubtful accounts

(d) Note 9 – deferred tax assets and liabilities

(e) Note 10 – recognition and measurement of regulatory balances

(f) Note 13 – recognition and measurement of employee future benefits

(g) Note 19 – recognition and measurement of provisions and contingencies

(h) Note 22 – measurement of fair value of derivatives

2. Basis of presentation (continued):

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

(ii) Judgements:

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

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

(b) Notes 3 (i), 10 – recognition of regulatory balances

(f) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, and among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate setting:

Distribution revenue:

For the distribution revenue included in revenues, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

2. Basis of presentation (continued):

(f) Rate regulation (continued):

Rate setting (continued):

Distribution revenue (continued):

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in 2016 for rates effective May 1, 2017. The OEB has approved the Corporation's request to defer the next COS application to rates effective May 1, 2025 and the Corporation will continue to file annual IRM applications until that time. The GDP IPI-FDD used for 2023 rates was 3.7%, the Corporation's productivity factor was 0.0% and the stretch factor was 0.0%, resulting in a net adjustment of 3.7% to the previous year's rates.

Electricity rates:

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity.

The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

Retail transmission rates:

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

2. Basis of presentation (continued):

(f) Rate regulation (continued):

Rate setting (continued):

Wholesale market service rates:

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

3. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements. The Corporation adopted Disclosure of Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2) effective January 1, 2023. These amendments require disclosure of material rather than significant accounting policies. The amendments provide guidance on the application of materiality to disclosure of accounting policies, assisting entities to provide useful, entity-specific accounting policy information. The amendments did not have a material impact on the Corporation’s financial statements.

(a) Financial instruments:

Financial assets and financial liabilities are recognized in the statements of financial position when the Corporation becomes a party to the contractual provisions of the instrument.

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognized immediately in profit or loss.

All regular way purchases or sales of financial assets are recognized and derecognized on a trade date basis. Regular way purchases or sales are purchases or sales of financial assets that require delivery of assets within the time frame established by regulation or convention in the marketplace. The Corporation recognizes all financial assets subsequently in their entirety at amortized cost except for derivative instruments.

3. Material accounting policies (continued):

(a) Financial instruments (continued):

(i) Classification and measurement of financial instruments:

The measurement and classification categories of financial assets in accordance with IFRS 9 at are outlined in the below table:

Financial asset/liability	IFRS 9
Cash and cash equivalents	Amortized cost
Accounts receivable	Amortized cost
Due from related parties	Amortized cost
Accounts payable and accrued liabilities	Amortized cost
Derivative instruments	Fair value through other comprehensive income
Customer deposits	Amortized cost
Long-term debt	Amortized cost

There were no changes to the classification and measurement of the balance sheet other than a new derivative instrument in the current year based on interest rate swaps entered into by the Corporation. The swaps are discussed in this note under financial liabilities.

(ii) Classification of financial assets:

Debt instruments that meet the following conditions are measured subsequently at amortized cost:

- The financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

(iii) Derecognition of financial assets:

The Corporation derecognizes a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. If the Corporation neither transfers nor retains substantially all the risks and rewards of ownership and continues to control the transferred asset, the Corporation recognizes its retained interest in the asset and an associated liability for amounts it may have to pay.

On derecognition of a financial asset measured at amortized cost, the difference between the asset's carrying amount and the sum of the consideration received and receivable is recognized in profit or loss.

3. Material accounting policies (continued):

(a) Financial instruments (continued):

(iv) Financial liabilities:

All financial liabilities other than derivative instruments are measured subsequently at amortized cost using the effective interest method.

The effective interest method is a method of calculating the amortized cost of a financial liability and of allocating interest expense over the relevant period.

The effective interest rate is the rate that exactly discounts estimated future cash payments (including all fees and points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial liability, or (where appropriate) a shorter period, to the amortized cost of a financial liability.

The Corporation entered into interest rate swap agreements to manage its exposure to interest rate fluctuations related to the $3,500, $13,500 and $2,500 loans presented in Note 12. Derivatives are recognized initially at fair value at the date the contract is entered into and are subsequently remeasured to their fair value at each reporting date. The resulting gain or loss is recognized through other comprehensive income immediately unless the derivative is designated and effective as a hedging instrument, in which event the timing of the recognition in other comprehensive income depends on the nature of the hedge relationship. The Corporation did not designate the instrument as a hedging instrument. Instead, the interest rate swap is marked to market at December 31, 2023 and the gain or loss is recognized in other comprehensive loss as Cash flow hedges-effective portion of changes in fair value.

(v) Derecognition of financial liabilities:

The Corporation derecognizes financial liabilities when, and only when, the Corporation’s obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

When the Corporation exchanges with the existing lender one debt instrument into another one with substantially different terms, such exchange is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. Similarly, the Corporation accounts for substantial modification of terms of an existing liability or part of it as an extinguishment of the original financial liability and the recognition of a new liability.

3. Material accounting policies (continued):

(b) Revenue recognition:

Sale and distribution of electricity:

Revenue from the sale and distribution of electricity is recognized as the electricity is delivered to customers on the basis of cyclical meter readings and estimated customer usage since the last meter reading date to the end of the year. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Other revenue:

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

Certain customers and developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. Cash contributions are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset. Capital contributions received from developers to construct or acquire capital assets for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15.

Government grants and the related performance incentive payments under Conservation Demand Management (“CDM”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received. Performance incentive payments are considered out of scope of IFRS 15 Revenue from Contracts with Customer [“IFRS 15”].

(c) Materials and supplies:

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

3. Material accounting policies (continued):

(d) Property plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labor, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

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

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

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

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

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

3. Material accounting policies (continued):

(d) Property plant and equipment (continued):

The estimated useful lives are as follows:

Asset	Years
Buildings	40 - 60
Distribution equipment	
Distribution stations	20 - 45
Poles and overhead/underground lines	50
Underground plant	20 - 50
Distribution transformers	40
Distribution meters	15
Other	4 - 60

(e) Intangible assets:

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

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization. Payments to obtain rights to access land ("land rights") are classified as intangible assets.

These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

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

The estimated useful lives are:

Asset	Years
Computer software	5
Land rights	25

3. Material accounting policies (continued):

(f) Impairment:

(i) Financial assets measured at amortized cost:

A financial asset is assessed using the lifetime expected credit losses (“ECL”) model to determine whether there is any objective evidence that it is impaired, using the simplified approach. This includes both quantitative and qualitative information and analysis, based on the Corporation’s historical experience, adjusted for forward-looking factors specific to the current credit environment.

The Corporation measures the loss allowance at an amount equal to the lifetime ECL for trade receivables or contract assets that result from transactions that are within the scope of IFRS 15, and do not contain a significant financing component. The Corporation uses a provision matrix to measure the lifetime ECL of accounts receivable from individual customers which accounts for exposures in different customer classes.

If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

(ii) Non-financial assets:

The carrying amounts of the Corporation’s non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset’s recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the “cash-generating unit” or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

3. Material accounting policies (continued):

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

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

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Regulatory balances:

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

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

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

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

3. Material accounting policies (continued):

(j) Post-employment benefits:

Pension plan:

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

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

Post-employment benefits, other than pension:

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

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management’s best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Finance income and finance costs:

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

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

3. Material accounting policies (continued):

(l) Income taxes:

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

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

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

Rate regulated accounting requires the recognition of regulatory balances and related deferred tax assets and liabilities for the amount of deferred taxes expected to be refunded to or recovered from customers through future electricity distribution rates.

4. Cash and cash equivalents:

	2023	2022
Bank balances	$ 3,764	$ 706

5. Accounts receivable:

	2023	2022
Trade receivables	$ 4,044	$ 3,546
Less loss allowance	(286)	(278)
	3,758	3,268
Other trade receivables	23	5
Billable work	288	109
	$ 4,069	$ 3,382

6. Materials and supplies:

Amount recovered pertaining to materials and supplies in 2023 was $3 (2022 - $19).

7. Property, plant and equipment:

	Land and building	Distribution equipment	Other fixed assets	Construction in progress	Total
Cost or deemed cost					
Balance at January 1, 2023	$ 2,299	$ 45,047	$ 5,726	$ 28	$ 53,100
Additions	36	4,273	453	132	4,894
Transfers	–	28	–	(28)	–
Disposals/retirements	–	(24)	(13)	–	(37)
Balance at December 31, 2023	$ 2,335	$ 49,324	$ 6,166	$ 132	$ 57,957
Accumulated depreciation					
Balance at January 1, 2023	$ (740)	$ (9,521)	$ (2,262)	$ –	$ (12,523)
Depreciation	(95)	(1,451)	(364)	–	(1,910)
Disposals/retirements	–	17	13	–	30
Balance at December 31, 2023	(835)	(10,955)	(2,613)	–	(14,403)
Carrying amount at December 31, 2023	$ 1,500	$ 38,369	$ 3,553	$ 132	$ 43,554
Cost or deemed cost					
Balance at January 1, 2022	$ 2,299	$ 41,396	$ 5,278	$ 48	$ 49,021
Additions	–	3,646	443	18	4,107
Transfers	–	33	5	(38)	–
Disposals/retirements	–	(28)	–	–	(28)
Balance at December 31, 2022	$ 2,299	$ 45,047	$ 5,726	$ 28	$ 53,100
Accumulated depreciation					
Balance at January 1, 2022	$ (645)	$ (8,191)	$ (1,911)	$ –	$ (10,747)
Depreciation	(95)	(1,346)	(351)	–	(1,792)
Disposals/retirements	–	16	–	–	16
Balance at December 31, 2022	(740)	(9,521)	(2,262)	–	(12,523)
Carrying amount at December 31, 2022	$ 1,559	$ 35,526	$ 3,464	$ 28	$ 40,577

At December 31, 2023 all property, plant and equipment are subject to a general security agreement.

Property, plant and equipment and intangible asset purchase commitments outstanding as at December 31, 2023 was $609 (2022 - $762).

8. Intangible assets:

		Computer software		Land rights		Construction in progress		Total
Cost or deemed cost								
Balance at January 1, 2023	$	861	$	10	$	25	$	896
Additions		10		–		–		10
Transfers		25		–		(25)		–
Disposals/retirements		–		–		–		–
Balance at December 31, 2023	$	896	$	10	$	–	$	906
Accumulated depreciation								
Balance at January 1, 2023	$	(585)	$	(6)	$	–	$	(591)
Depreciation		(139)		(1)		–		(140)
Disposals/retirements		–		–		–		–
Balance at December 31, 2023		(724)		(7)		–		(731)
Net book value at December 31, 2023	$	172	$	3	$	–	$	175
Cost or deemed cost								
Balance at January 1, 2022	$	853	$	10	$	18	$	881
Additions		8		–		7		15
Transfers		–		–		–		–
Disposals/retirements		–		–		–		–
Balance at December 31, 2022	$	861	$	10	$	25	$	896
Accumulated depreciation								
Balance at January 1, 2022	$	(438)	$	(5)	$	–	$	(443)
Depreciation		(147)		(1)		–		(148)
Disposals/retirements		–		–		–		–
Balance at December 31, 2022		(585)		(6)		–		(591)
Net book value at December 31, 2022	$	276	$	4	$	25	$	305

9. Income tax expense:

		2023		2022
Current tax expense:				
Current year expense	$	368	$	48
Deferred tax expense:				
Changes in recognized deductible temporary differences		390		569
Income tax expense	$	758	$	617

Reconciliation of effective tax rate:

		2023		2022
Income before income taxes	$	2,861	$	1,396
Canada and Ontario statutory income tax rates		26.5%		26.5%
Expected tax provision on income at statutory rates	$	758	$	370
Decrease in income taxes resulting from:				
Corporate minimum tax		–		(195)
Other and prior period adjustments		–		442
Income tax expense	$	758	$	617

Significant components of the Corporation’s deferred tax (liability) asset balance:

		2023		2022
Deferred tax (liabilities) assets:				
Property, plant and equipment	$	(1,519)	$	(1,238)
Regulatory balances		(49)		(68)
Post-employment benefits		263		242
Corporate minimum tax		46		195
	$	(1,259)	$	(869)

10. Regulatory balances:

	January 1, 2023	Additions	Recovery/ additions	December 31, 2023	Remaining Recovery/ reversal year
Regulatory deferral account debit balance:					
Group 1 deferred accounts	$ 1,683	$ 42	$ (548)	$ 1,177	–
Regulatory transition to IFRS	36	1	–	37	–
Regulatory settlement accounts	94	(1)	–	93	–
Other regulatory accounts	159	43	–	202	–
Income tax	995	–	261	1,256	–
	$ 2,967	$ 85	$ (287)	$ 2,765	

	January 1, 2022	Additions	Recovery/ additions	December 31, 2022	Remaining Recovery/ reversal year
Regulatory deferral account debit balance:					
Group 1 deferred accounts	$ 357	$ 1,152	$ 174	$ 1,683	–
Regulatory transition to IFRS	35	1	–	36	–
Regulatory settlement accounts	84	10	–	94	–
Other regulatory accounts	133	26	–	159	–
Income tax	584	–	411	995	–
	$ 1,193	$ 1,189	$ 585	$ 2,967	

	January 1, 2023	Additions	Recovery/ reversals	December 31, 2023	Remaining Recovery/ reversal year
Regulatory deferral account credit balances:					
Group 1 deferred accounts	$ (800)	$ (222)	$ 542	$ (480)	–
Regulatory settlement account	(160)	134	–	(26)	–
Other regulatory accounts	(1,442)	(83)	–	(1,525)	–
Income tax	–	–	–	–	–
	$ (2,402)	$ (171)	$ 542	$ (2,031)	

10. Regulatory balances (continued):

	January 1, 2022	Additions	Recovery/ reversals	December 31, 2022	Remaining Recovery/ reversal year
Regulatory deferral account credit balances:					
Group 1 deferred accounts	$ (736)	$ (275)	$ 211	$ (800)	–
Regulatory settlement account	(125)	(35)	–	(160)	–
Other regulatory accounts	(953)	(489)	–	(1,442)	–
Income tax	–	–	–	–	–
	$ (1,814)	$ (799)	$ 211	$ (2,402)	

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. An application was made and approved by the OEB to recover $961 of the Group 1 deferral accounts over a one-year period beginning May 1, 2024. The approved account balance will be moved to the regulatory settlement account. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2023 the rate ranged from 4.73% to 5.49%.

11. Accounts payable and accrued liabilities:

	2023	2022
Accounts payable – energy purchases	$ 4,585	$ 4,072
Payroll payable	136	171
Other	1,415	908
	$ 6,136	$ 5,151

12. Long-term debt:

	2023	2022
Notes payable	$ 20,177	$ 17,968
Current portion	(341)	(213)
	$ 19,836	$ 17,755

Notes payable is comprised of a $1,500 interest only loan with TD Bank which bears interest at 3.62%, a $13,500 interest only swap agreement with TD Bank which bears interest at 2.805%, a $3,500 principal and interest rate swap agreement with TD Bank which bears interest at 1.972% and a $2,500 principal and interest rate swap agreement with TD Bank which bears interest at 4.493%. The loans are due January 2029, December 2029, May 2035, and May 2038 respectively.

Repayment of the long-term debt for the years ended December 31:

2024	$ 341
2025	351
2026	361
2027	372
Thereafter	18,752
	20,177
Current portion	(341)
Long-term portion	$ 19,836

13. Post-employment benefits:

(a) OMERS pension plan:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2023, the Corporation made employer contributions of $370 to OMERS (2022 - $352), of which $62 (2022 - $57) has been capitalized as part of PP&E and the remaining amount of $308 (2022 - $295) has been recognized in profit or loss or charged to billable work.

As at December 31, 2023, OMERS had approximately 612,533 members, of whom 32 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2023, which reported that the plan was 97% funded, with an unfunded liability of $4.2 billion (2022 - $6.7 billion). This unfunded liability is likely to result in future payments by participating employers and members.

13. Post-employment benefits (continued):

(b) Post-employment benefits other than pension:

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

	2023	2022
Reconciliation of the obligation		
Defined benefit obligation, beginning of year	$ 913	$ 1,268
Included in profit or loss		
Current service cost	14	22
Interest cost	43	36
	970	1,326
Included in OCI		
Actuarial gains arising from changes in demographic and financial assumptions	170	(267)
Benefits paid	(146)	(146)
Defined benefit obligation, end of year	$ 994	$ 913

	2023	2022
Actuarial assumptions:		
General inflation	2.00%	2.00%
Discount (interest) rate	4.60%	5.05%
Salary levels	3.30%	3.30%
Medical costs	4.90%	4.70%
Dental costs	5.10%	4.90%

A 1% increase in the assumed discount rates would result in the defined benefit obligation decreasing by $97. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $123.

14. Share capital:

	2023	2022
Authorized:		
Unlimited number of common shares		
Issued:		
1,000 common shares	$ 12,953	$ 12,953

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

The Corporation paid aggregate dividends in the year on common shares of 1,100 dollars per share (2022 - $1,000), which amount to total dividends paid in the year of $1,100 (2022 - $1,000).

15. Revenue:

Revenue consists of the following:

	2023	2022
Revenue from contracts with customers:		
Energy sales	$ 45,116	$ 46,109
Distribution revenue:		
Distribution	11,762	11,146
Third party services	41	31
Pole rentals	240	230
Miscellaneous	291	321
Generation	28	29
Revenue from other sources:		
Contributions received from customers	128	102
	$ 57,606	$ 57,968

16. Employee salaries and benefits:

	2023	2022
Salaries, wages and benefits	$ 2,908	$ 2,909
CPP and EI remittances	134	129
Contributions to OMERS	291	282
Post-employment benefit plan	104	104
	$ 3,437	$ 3,424

17. Operating expenses:

	2023	2022
Operations and maintenance	$ 2,056	$ 2,030
Customer service and billing	885	881
Administrative, finance, and IT	900	820
	$ 3,841	$ 3,731

18. Finance income and costs:

	2023	2022
Finance income:		
Interest income on bank deposits	$ 221	$ 61
Finance costs:		
Interest expense on long-term debt	566	494
Interest expense on customer deposits	45	14
Interest expense - other	–	8
	611	516
Net finance costs recognized in profit or loss	$ 390	$ 455

19. Commitments and contingencies:

Independent Electricity System Operator:

As of May 1, 2002 in order for the Corporation to obtain the electricity it requires to distribute to its customers, the Corporation was required to provide security to the Independent Electricity System Operator (IESO) based on its usage. The security obtained was a letter of credit from a financial institution, which requires an interest coverage ratio of more than 1.5 and a debt capitalization ratio of less than 0.6. The letter is in the amount of $ and incurs interest at 0.6% annually.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2023, no assessments have been made.

20. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Welland Hydro-Electric Holding Corp., which in turn is wholly-owned by the City of Welland. The City produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

	2023	2022
City of Welland	$ 96	$ 142

20. Related party transactions (continued):

(c) Transactions with parent (Welland Hydro-Electric Holding Corp.) and affiliates:

The following amounts were invoiced to parent and affiliates in the normal course of operations:

		2023		2022
Welland Hydro-Electric Holding Corp.				
Management fees and employee services	$	12	$	11
Welland Hydro Energy Services Corp.				
Management fees		9		9
Streetlight/sentinel maintenance and administration		14		11
	$	35	$	31

(d) Transactions with ultimate parent (City of Welland):

The Corporation delivers electricity to the City/Town throughout the year for the electricity needs of the City/Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the City/Town, including sentinel lights.

The following amounts were invoiced to the City of Welland in the normal course of operations:

		2023		2022
Energy (at commercial rates)	$	1,101	$	1,092
Rent		10		28
	$	1,111	$	1,120

The following expenses were incurred with the City of Welland in the normal course of operations:

		2023		2022
Property taxes and other taxes	$	62	$	59
Leases and miscellaneous		16		12
Water		4		4
	$	82	$	75

21. Key management personnel:

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

	2023	2022
Director's fees	$ 67	$ 69
Salaries and other short-term benefits	684	708
	$ 751	$ 777

22. Financial instruments and risk management:

Fair value disclosure:

The following methods and assumptions were used to estimate the fair value of financial instruments:

- The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments.
- The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.
- Fair value measurement of the derivative instruments is determined on the basis of a discounted cash flow model using inputs that are based on observable market data (i.e. Level 2 inputs). Estimate of future floating-rate cash flows are based on quoted swap rates and future prices. Estimated cash flows are discounted using a yield curve constructed from similar sources and which reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps.

Fair value hierarchy:

Financial instruments recorded at fair value are classified using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);
Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

22. Financial instruments and risk management (continued):

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, market risk (including currency risk, interest rate risk, and price risk), as well as related mitigation strategies, are discussed below.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Welland. No single customer accounts for a balance in excess of 2.3% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the loss allowance at the end of the year at an amount equal to lifetime ECL recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance for impairment at December 31, 2023 is $286 (2022 - $278). An impairment loss of $114 (2022- $150) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2023, approximately $286 (2022 - $278) is considered 60 days past due. The Corporation has over twenty-five thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB and through credit insurance. As at December 31, 2023, the Corporation holds security deposits in the amount of $946 (2022 - $961) for electrical accounts.

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation uses derivative instruments to reduce its exposure to interest risk. As at December 31, 2023, the Corporation is committed to a swap transaction on a $13,500 loan with an interest rate of 2.805% maturing December 20, 2029, a swap transaction on a $3,500 loan with an interest rate of 1.972% maturing May 26, 2035, and a swap transaction on a $2,500 loan with an interest rate of 4.493% maturing April 14, 2038. The mark of the derivatives at December 31, 2023 is $1,011 (2022 – $1,508). The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates. Current deemed interest rates used by the OEB to set distribution rates approximate those included in the Corporation's current distribution rates and would not have a material impact when rates are rebased. There has been no change in the Corporation's exposure to market risks or the manner in which these risks are managed and measured.

22. Financial instruments and risk management (continued):

Financial risks (continued):

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $2.0 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2023, no amounts had been drawn under the Corporation's $2.0 million credit facility.

The majority of accounts payable, as reported on the statement of financial position, are due within 15 to 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2023, shareholder's equity amounts to $23,011 (2022 - $22,336) and long-term debt amounts to $20,177 (2022 - $17,968).

Appendix 1-F: Customer Engagement Survey

Welland Hydro

24th Annual

Electric Utility Customer Satisfaction Survey

UtilityPULSE

Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

The purpose of this report is to profile the connection between Welland Hydro Ltd (Welland Hydro) and its customers.

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

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

This survey report is privileged and confidential material, and no part may be used outside of Welland Hydro without written permission from UtilityPULSE Inc.

All comments and questions should be addressed to:

UtilityPULSE Inc.
David Malesich
President
Email: david@utilitypulse.com

Survey Observations & Insights

Worries about paying for electricity have once again reared its ugly head. While financial worries declined in the past couple of years in relation to the larger pandemic, more customers are now worried about the cost of electricity and more customer focus is on their concern about their ability to pay their utility bills within a period of rising inflation and increased economic uncertainty. This survey asked respondents to pick from 4 statements the one which best describes their ability to pay. In 2020, 19% [Ontario Benchmark] and 28% [Welland Hydro] said that *"Paying for electricity is at least sometimes a worry"*. Comparatively, in 2022, 39% of Ontarians and 41% of Welland Hydro customers have this concern. Consequently, it is not surprising that "Price and Value" is the area rated least positively for Welland Hydro and other LDCs.

Paying for electricity is at least sometimes a worry	2022	2021	2020	2019	2018	2017
Welland Hydro	41%	-	28%	-	29%	-
National	35%	18%	19%	24%	25%	31%
Ontario	39%	19%	19%	27%	30%	37%

Base: total respondents / (-) not a participant of the survey year

Bills and payments are increasing outside of the utility world, which is increasing the "worry" factor. Survey respondents are looking through the lens of costs, more specifically affordability, but so far they continue to be satisfied with the overall operation and the image of Welland Hydro. While many appear to be venting about their general financial situations, ability to pay is a highly correlated factor to overall satisfaction, and given the steep rise in inflation rates and a potential recession in 2023 (which are beyond the control of your LDC), current positive impressions could be impacted over the next few years, and the increase in financial uncertainly has seen a softening of overall satisfaction, although it still remains high at this time. That said, one issue is causing a general negative halo preventing even better overall impressions and performance: power reliability. The biggest challenges facing Welland Hydro are outages and this is an area where customers primarily want to see improvements. Many even perceive outages to be increasing in frequency. Keep in mind that the Killer B’s, bills and blackouts, remain primary sources of dissatisfaction and financial worries are only exacerbating customers’ negative perceptions (even if they are not based in reality).

We recommend everyone at Welland Hydro remain professional and demonstrate empathy and as we know about human nature, worry can easily turn into a severe erosion of trust which then leads to anger. Thankfully, positive customer service interactions are limiting the potential adverse impact of outages at this time.

Paying for Electricity

Survey respondents were generally less negative about the cost of electricity compared to other utilities and some feel they could be getting better value, but this is a challenge for the industry as a whole.

Cost/Value Attributes

	Welland Hydro	National	Ontario
Provides good value for your money	82%	73%	71%
Operates a cost-effective electricity system	81%	74%	70%
Cost of electricity is reasonable compared to other utilities	78%	71%	69%
Provides info/tools to help manage electricity consumption	84%	79%	78%

Base: total respondents with an opinion

Many are worried about paying for electricity and future impressions may start to decrease as customers take out their financial frustrations on Welland Hydro.

Is paying for electricity a worry or a major problem?

	Not a worry	Sometimes	Often	Depends
Welland Hydro	56%	31%	4%	6%
National	62%	24%	6%	5%
Ontario	58%	26%	6%	7%

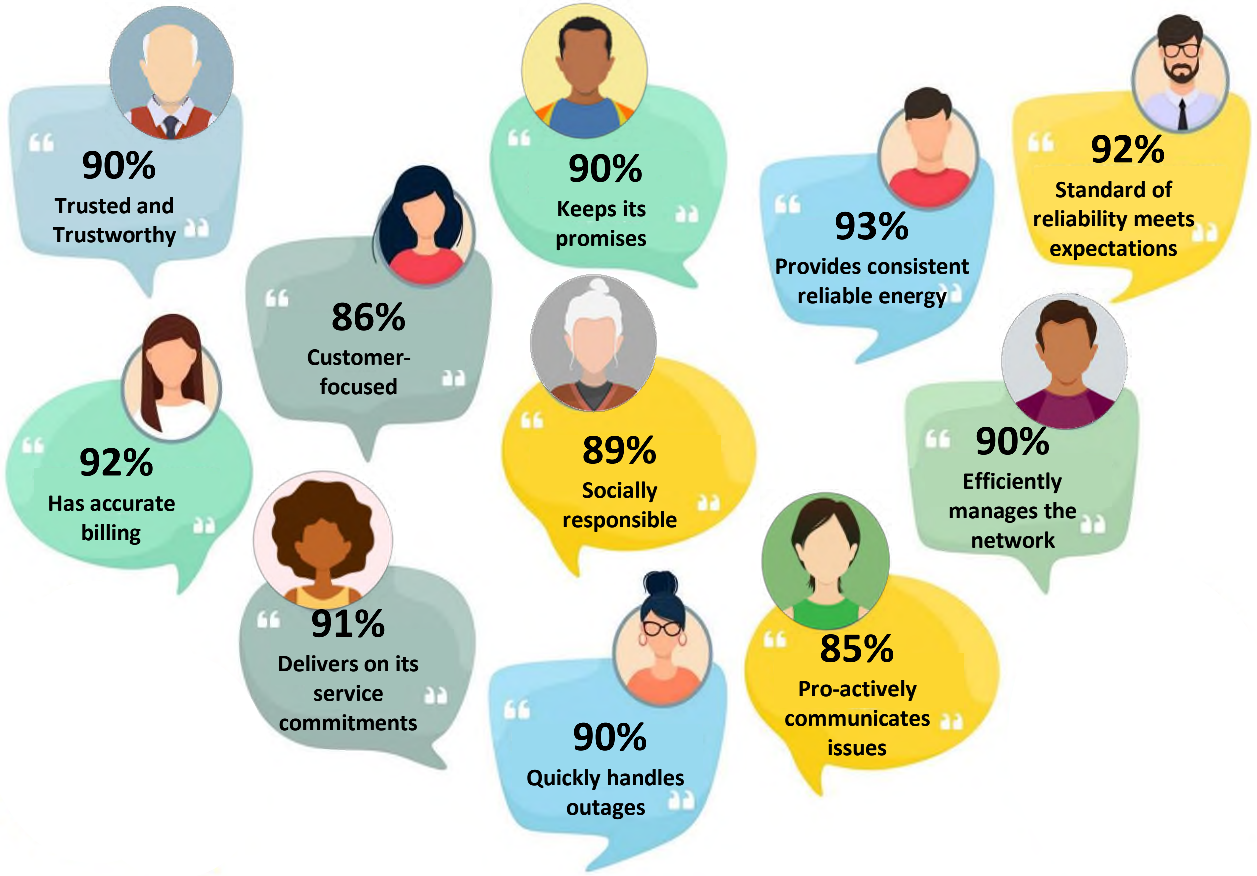
Base: total respondents

Those with financial worries have more negative perceptions of cost and value attributes.

Cost/Value Attributes By Ability to Pay for Electricity					
	Welland Hydro	Not a worry	Sometimes	Often	Depends
Provides good value for your money	82%	87%	76%	63%	71%
Operates a cost-effective electricity system	81%	85%	78%	60%	69%
Cost of electricity is reasonable compared to other utilities	78%	84%	74%	52%	72%
Provides info/tools to help manage electricity consumption	84%	87%	82%	59%	81%

Base: total respondents with an opinion

Overall, Welland Hydro Scores remain high, which is very encouraging; for example, Welland Hydro's satisfaction score is 97% (pre-measure) and 91% say they will continue to do business with Welland Hydro.



90% Trusted and Trustworthy

92% Has accurate billing

86% Customer-focused

91% Delivers on its service commitments

90% Keeps its promises

89% Socially responsible

90% Quickly handles outages

93% Provides consistent reliable energy

85% Pro-actively communicates issues

92% Standard of reliability meets expectations

90% Efficiently manages the network

Base: total respondents with an opinion

Issues: Billing and Blackouts, the “Killer B’s”

The reliable and efficient delivery of electricity to homeowners and businesses is an essential service – especially during the personal and professional challenges of the past couple of years. Customers can be comforted by the fact that standards for keeping the lights on and getting them up and running quickly have not deteriorated. Less than a third of Welland Hydro customers are reporting outages in the past 12 months (less than the province). Actively communicating with customers during these times will limit adverse impacts.

Problems: Blackouts

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	Welland Hydro	National	Ontario
2022	27%	43%	48%

Base: total respondents

Investing more in the electricity grid to reduce outages is seen as the biggest priority for Welland Hydro.

Priority Planning Within the Next 5 Years

Top 2 Boxes: ‘very high + high priority’	Welland Hydro
Investing more in the electricity grid to reduce outages	97%
Preventing data breaches and system disruptions due to cyberattack	96%
Reducing response times to outages	96%
Educating the public as it relates to electricity safety	82%
Increasing the use of e-billing and paper-free communication options to reduce environmental impact and improve cost-effectiveness	79%
Providing more self-serve services on the website	62%
Increasing the use of social media (such as Twitter, Facebook, and others)	51%

Base: total respondents with an opinion

Problems: Billing issues

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	Welland Hydro	**National**	**Ontario**
2022	5%	10%	13%

Base: total respondents

Digital Communication

About half of Welland Hydro customers say they visit the website to try to resolve their own issues before contacting you. However, many customers desire personal touch and even though they can do it and have an increasing comfort level with technology many still want the personal touch of a customer service agent. Multiple channels need to be made available.

Visited website to try to resolve issue on own, or get more clarity, before contacting utility		
	Welland Hydro	**UP Database**
Yes	56%	49%

Base: respondents contacting utility, small sample size

The movement to digitization and self-serve is welcomed and embraced by many due to increasing comfort with technology, utilities must still proceed with caution. Too much, forced too soon may cause frustration. Many still want the personal touch of a customer service agent. For example, most are open to e-billing with Welland Hydro, but they still would rather use the website for a call back than for live chat.

Interest in Communication Options From Welland Hydro

Top 2 Boxes: 'very + somewhat important'	Welland Hydro
E-billing (paperless option)	89%
Request for call back on website	82%
Email (including e-blasts)	80%
Telephone	80%
Ability to receive updates via SMS/text	67%
Live chat on website	63%
Letter mail	48%

Base: total respondents with an opinion

Ultimately, customers want the flexibility of being able to engage on their terms based on their circumstances and needs and want processes that solve problems or get service that is “fast”, “easy”, with “little effort”.

Many are open to email and text for learning about unexpected outages.

Preferred method of communication Welland Hydro should use during an UNEXPECTED Outage

Text message alert	43%
Email alert/notice	43%
Recorded telephone message alert	32%
A toll-free or call-in outage line	29%
Social media alert	15%
Other	15%
Don't recall / Don't know	14%

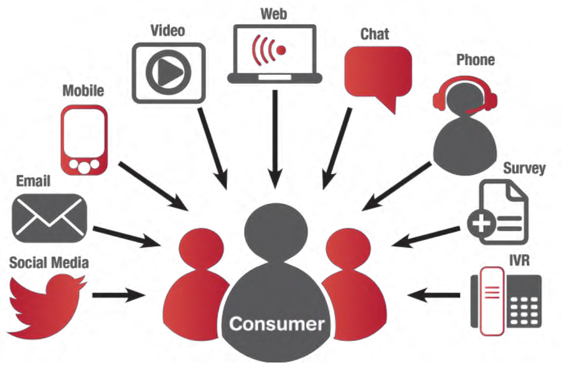
Base: total respondents

Customers are also generally satisfied with the education and information they are currently receiving from Welland Hydro.

Satisfaction With Education and Information Received From Welland Hydro

Top 2 Boxes: 'very + somewhat satisfied'	Welland Hydro
The quality of information about the various payment options available to you	92%
The electricity safety education provided to the public	91%
The timing of information for things such as planned outages, construction activity, tree-trimming	91%
Regulated changes in regards to rates, customer service rules and programs	88%
The quality of information about the two different rate options available to you	85%
The quality of information available when outages occur	84%

Base: total respondents with an opinion



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

Customer Service

Customers are more concerned about outcomes and want their issues, problems, or concerns to be dealt with in a professional, knowledgeable, and timely manner. Respondents were asked about six aspects of their more recent experience.

Satisfaction with Customer Service

Top 2 Boxes: 'very + fairly satisfied'	Welland Hydro	National	Ontario
The time it took to contact someone	76%	72%	63%
The time it took someone to deal with your problem	73%	70%	66%
The helpfulness of the staff who dealt with you	78%	76%	71%
The knowledge of the staff who dealt with you	89%	81%	75%
The level of courtesy of the staff who dealt with you	92%	87%	81%
The quality of information provided by the staff who dealt with you	76%	79%	75%

Base: respondents contacting utility; small sample size

The Core Responsibilities

Survey respondents generally gave Welland Hydro very strong operational and representative scores. Those who have more of a problem paying their electricity bill are notably less likely to agree that Welland Hydro “has accurate billing.”

Core Operational Attributes

	Welland Hydro	National	Ontario
Provides consistent, reliable energy	93%	86%	85%
Quickly handles outages and restores power	90%	84%	83%
Has accurate billing	92%	85%	85%
Has a standard of reliability that meets expectations	92%	85%	84%
Makes electricity safety a top priority	94%	87%	86%

Base: total respondents with an opinion

Core Operational Attributes By Ability to Pay Electricity Bill

	Welland Hydro	Not a worry	Sometimes a worry	Often a problem	Depends
Provides consistent, reliable energy	93%	95%	90%	80%	90%
Has a standard of reliability that meets expectations	92%	94%	91%	81%	87%
Has accurate billing	92%	95%	88%	73%	91%

Base: total respondents with an opinion

Customer service quality attributes are generally favourable for Welland Hydro and higher than key benchmarks.

Core Customer Service Quality Attributes

	Welland Hydro	National	Ontario
Customer-focused and treats customers as if they're valued	86%	78%	77%
Deals professionally with customers' problems	90%	81%	80%
Is pro-active in communicating changes and issues	85%	79%	78%
Delivers on its service commitments to customers	91%	83%	83%
Is 'easy to do business with'	89%	82%	82%
Adapts well to changes in customer expectations	84%	77%	75%

Base: total respondents with an opinion

Customer Effort & Experience Score™ (CEES)

Customers are time-pressed, and they want transactions related to getting questions answered or solving problems to be easy and fast. Customers dislike non-seamless handoffs when they have to deal with different people or departments to address their issues, and they dislike a slow response to their problem or concern. Customers also dislike "surprises" which is why they expect their utility to communicate with them pro-actively and, when needed, be 'easy to do business with'.

The CEES as a metric is designed to help the organization remain focused on making things easy and fast for customers. The goal is to encourage improvements in all aspects of the customer's journey from initial contact to completion of the issue. The central idea of CEES is about getting the most from your investments in people and technology.

Welland Hydro has rated a Customer Effort & Experience Score (CEES)^{TM} of 54%**.** The Ontario benchmark is 23%, and the UtilityPULSE database average is 35%.

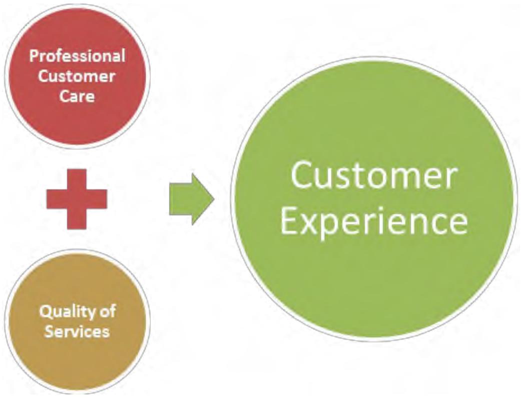
Customer Effort & Experience Score (CEES)			
	Opportunity Range <15%	**Good Range 15-34%**	**Very Good Range 35+%**
Welland Hydro			54%
National Benchmark		25%	
Ontario Benchmark		23%	
UP Database			35%

Base: total respondents; range bands represent 2022 data and can change year-to-year

The Customer Effort & Experience Score™ is about encouraging your people to figure out how to speed up and simplify interactions. It is designed to encourage dialogue with all areas of the business to reduce customer effort. Busy, time-pressed customers consider CEES a bona fide reflection of the business. Most importantly, it has a direct correlation to customer satisfaction, loyalty, and NSS.

Our experience suggests that low-effort experiences, i.e., “easy” and “fast,” are highly correlated to customer affinity (loyalty). In contrast, high-effort experiences are correlated to low overall satisfaction and low company image.

Customer Experience Performance rating (CEPr)



Every touchpoint with customers on the phone, email, text, website, or in-person influences what customers think and feel about the organization. When an interaction with a customer meets their expectation, the opportunity to build loyalty (affinity) and support is strong. When the experience is a negative one, customers often conclude that the organization doesn’t care.

A positive experience today sets up the perception that future interactions will also be excellent.

Customer Experience Performance rating (CEPr)

	Welland Hydro	National	Ontario
CEPr: all respondents	90%	83%	82%

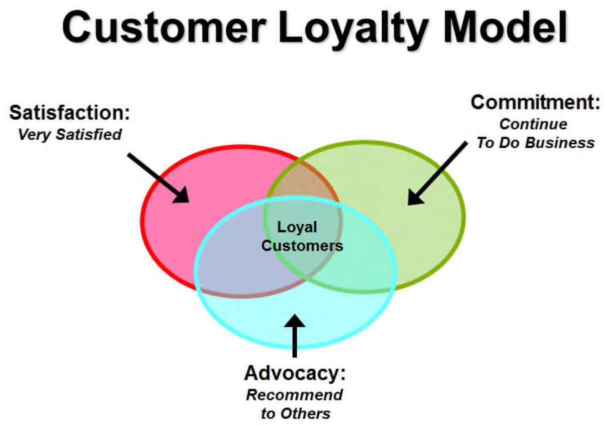
Base: total respondents

The CEPr rating suggests that a very large majority of customers have a belief that they will have a good to excellent experience dealing with Welland Hydro professionals.

From an image point-of-view, Welland Hydro received very good scores for the attributes “keeps its promises to its customers and the community” and “overall the utility provides excellent quality services”.

Customer Satisfaction

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



SATISFACTION SCORES – Electricity customers’ satisfaction			
Top 2 Boxes: ‘very + fairly satisfied’	**Welland Hydro**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	97%	92%	90%
POST: End of Interview	98%	91%	90%

Base: total respondents with an opinion

When it comes to the question of satisfaction, UtilityPULSE has designed the survey so that customers are asked twice, once at the beginning – this is to garner first impressions and set the tone for the survey, and again at the end – because now the respondent has context of what is being asked and is more aptly ready to address it in an informed state of mind.

Customer Commitment and Customer Advocacy

It is important to understand how committed your customers are to doing business with you again and how likely they are to recommend you to others. Every utility has an obligation to satisfy its customers. But the rewards for satisfying customers go far beyond “obligation.” Customer satisfaction is the bedrock for creating loyal customers. The two other measures which make the loyalty measure are:

- Customer commitment, i.e., wanting to continue to do business with you
- Customer advocacy, i.e., willing to recommend your organization to others.

Customer commitment is about identifying the number of customers who feel they “want to” vs. “have to” do business with you. Potential benefits of commitment may include positive word of mouth – an important aspect of loyalty. Committed customers have been known to demonstrate several beneficial behaviours; for example, committed customers tend to:

- Come to you when they need a product or service
- Try new initiatives
- Trust your recommendations
- Be more tolerant of bill increases

- Be more receptive of your viewpoints on various issues
- Be more tolerant of errors or issues
- Perceive you as well-managed.

Customer advocacy means that your customers are willing to recommend you to others. If your customers are willing to endorse you and put their reputation on the line to recommend you, they also trust you and are satisfied with the service you are providing.

More customers feel committed to Welland Hydro (91%) than likely to endorse you to other people (89%). Encouragingly, scores are very strong relative to key benchmarks.

Customer Commitment & Advocacy Scores

	Welland Hydro	National	Ontario
Continue to do business with	91%	84%	82%
Recommend to others	89%	80%	78%

Base: total respondents with an opinion

What is the importance of Net Supporter Score™ [NSS] for LDCs?

The NSS is a metric which measures how likely customers could ***support*** policy changes, actions, programs, or service changes or enhancements the LDC wishes to make. The NSS is a metric developed to help the organization, and its people, continue on a path of improving customer experiences, whether those experiences are in-person, over the telephone, online, or a combination. In a nutshell, the NSS reflects the net number of customers who have confidence in the LDC to continue to serve in their best interests.

Welland Hydro has a Net Supporter Score™ (NSS) of 36%**.** The Ontario benchmark is 11%, and the UtilityPULSE database average is 20%.

	Net Supporter Score™ (NSS)		
	Opportunity Range <10%	**Good Range 10-19%**	**Very Good Range 20+%**
Welland Hydro			36%
Ontario Benchmark		11%	

Base: total respondents; range bands represent 2022 data and can change year-to-year

What is the importance of Net Promoter Score™ (NPS) for LDCs?

The Net Promoter Score™ (NPS) is a popular metric that measures how likely customers are to recommend a business's products and services. Your NPS score, when compared to the benchmarks, can provide some insight into the affinity level of survey respondents towards your brand image. The NPS metric was developed by and is a registered trademark of Fred Reichheld, Bain & Company, and Satmetrix in 2003.

Welland Hydro has a strong Net Promoter Score^{TM} (NPS) of 58%**.** The Ontario benchmark is 21%, and the UtilityPULSE database average is 37%.

Net Promoter Score^{TM} (NPS)

	Opportunity Range <5%	Good Range 5-24%	Very Good Range 25+%
Welland Hydro			58%
Ontario Benchmark		21%	

Base: total respondents; range bands represent 2022 data and can change year-to-year

Loyalty Groups – Customer Affinity

Customer loyalty (affinity) is an intangible asset with positive consequences or outcomes associated with it, no matter the industry. Data shows that “Secure” customers have fewer outages and billing issues than “At Risk” customers, i.e., those that hate the utility. In private industry, loyalty is a behavioural metric; in a monopoly, it is an attitudinal metric.

Customer Loyalty Groups

	Secure	Favorable	Indifferent	At Risk
Welland Hydro	41%	19%	37%	4%
National	21%	18%	54%	6%
Ontario	19%	17%	57%	8%

Base: total respondents

Customer Centric Engagement Index (CCEI)

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

Utility Customer Centric Engagement Index (CCEI)

	Welland Hydro	National	Ontario
CCEI	88%	81%	80%

Base: total respondents

Credibility & Trust Index

In a world with heightened unknowns, people will look for credible organizations that can be trusted. 90% of respondents report that Welland Hydro is trusted and trustworthy. 90% believe that Welland Hydro keeps its promises.

Your Credibility & Trust score is 89%, while the Ontario benchmark is 82% and the National benchmark sits at 81%.

UtilityPULSE Report Card®

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

Welland Hydro's UtilityPULSE Report Card®

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

Base: total respondents

Numbers at a Glance for 2022

	Welland Hydro	National	Ontario
Customer Satisfaction: Initial	97%	92%	90%
Customer Satisfaction: Post	98%	91%	90%
Customer Advocacy	89%	80%	78%
Customer Commitment	91%	84%	82%
Customer Experience Performance Rating (CEPr)	90%	83%	82%
Customer Centric Engagement Index (CCEI)	88%	81%	80%
Credibility & Trust Index	89%	82%	81%
UtilityPULSE Report Card©	A	A	B+

Your survey was conducted from December 1 – December 6, 2022 and is based on 400 telephone and online surveys with residential and small commercial customers who pay or look after the electricity bill. In addition, survey findings for Welland Hydro are enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National Benchmark studies.

Consistent with the past 24 years, the number one suggestion, by a wide margin, has been “better prices”. Price will always be top of mind for customers. For 2022, the second-highest suggestion was “better information on outages when they occur.” Customers don’t want to be surprised by outages. They already have enough on their plates and are dealing with many other worries like the ability to pay their bills. They will ultimately take out their frustrations on everything that has a cost associated with it, including their utilities. More disconnects are likely over the next few years and utilities need to be prepared on how best to deal with this and ensure appropriate training is available to mitigate customer backlash.

Everyone in the LDC affects a customer's perception and not just call-centre employees. Employees in other departments interact with customers and so do outside-workers. Employees, at all levels and departments of the LDC are not immune to the frustration and anger customers feel about their bills and the industry as a whole. Therefore, it is imperative everyone remain professional and focused on doing everything very well – including the little things.

Upset or angry people are critical people and they will look for behaviours which reinforce or validate their negative view. It is more important than ever to ensure every interaction with a customer is an excellent one. Demonstrating understanding through active listening is a good start.

In a world of financial struggles, LDCs must consistently communicate their values to customers. Customer affinity grows when LDCs show they understand the worries, concerns and issues customers face because of the current state of the economy. A communication strategy demonstrating congruency with customer values will help build the brand and reputation of the LDC.

UtilityPULSE
David Malesich
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December 2022

Table of Contents

Table of Contents

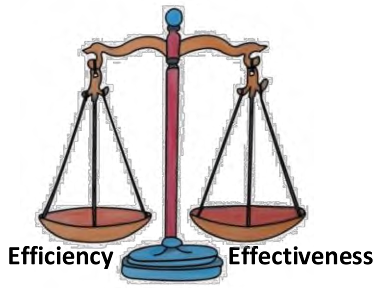
Satisfaction (pre & post)

As stated multiple times over many years, measuring satisfaction is an important starting point for creating loyal customers. However, it is a misnomer to conclude that highly satisfied customers are also customers with a high affinity or loyalty quotient. One can be satisfied but not necessarily loyal. But it is proper to conclude that the LDC (its people) must do the job as expected and required before there can be a positive emotional connection.

We've stated in the past, a focus on satisfaction prompts an organization to continue to evolve in ways that make sense to those who pay the bills. A focus on satisfaction is a focus on effectiveness in the delivery of service to the customer. Satisfied customers who trust their LDC may be more likely to seek advice, i.e., energy efficiency methods, and be more receptive to important messages, i.e. safety, new capital projects, etc.

About ratings/measures:

- Satisfaction is not a program; it is an outcome.
- ***Efficiency*** *is about achieving objectives with the minimum amount of people, time, money, and other resources; doing things right; resource usage*
- ***Effectiveness*** *ratings are measures keeping the organization and its people more future-focused than efficiency ratings; doing the right things; goal attainment*



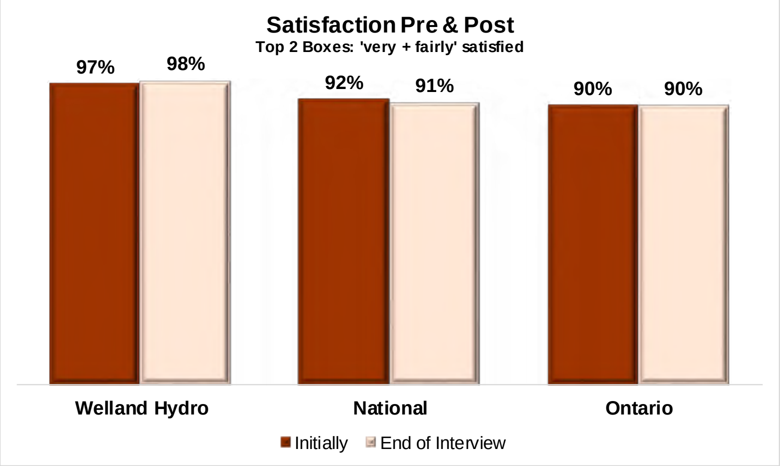
Finding the right balance between efficiency and effectiveness measures is difficult.

Efficiency ratings won't lead to satisfaction, but they can lead to dissatisfaction. Taking 90 seconds to answer the phone will create an agitated customer who, for the most part, starts off being dissatisfied with the service – before you've even had a chance to deal with or solve their problem. Answering the phone in 20 seconds but not solving the customer's problem will not ameliorate the customer's perception of the transaction.

Customer expectations of their electricity LDC have evolved past the "provide electricity reliably, safely, and billed both accurately with fair pricing." They do expect their LDC to be ethical, forward-thinking, competent, and trustworthy.

Satisfaction happens when utility core services meet or exceed customers' needs, wants, or expectations.

Loyalty occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.



Base: total respondents with an opinion

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company, along with satisfaction, identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

Electricity bill payers who are 'very' or 'fairly satisfied'					
	2022	**2021**	**2020**	**2019**	**2018**
Welland Hydro	97%	-	95%	-	96%
National	92%	94%	96%	93%	91%
Ontario	90%	93%	95%	92%	91%

Base: total respondents with an opinion / (-) not a participant of the survey year

In the UtilityPULSE Customer Satisfaction survey, the overall satisfaction question is asked both at the beginning (PRE) and the end (POST). Asking the general satisfaction question at the start of the survey avoids bias, obtaining a spontaneous rating. This allows measurement of customers' overall impressions of the utility before prompting them to think of specific aspects of the relationship. After asking about specific aspects of the customer experience, we gain a more *considered* (or conditioned) response.

As with any enterprise, Welland Hydro is obligated to satisfy its customers. But the rewards for satisfying customers go far beyond "obligation." Customers with high levels of satisfaction handle problems far better than customers with low satisfaction. Stronger relationships with customers generate higher levels of involvement and participation. For employees serving customers who are very satisfied, those interactions are more enjoyable s than those with customers who are very dissatisfied. Satisfied and engaged employees who work in an organizational culture that promotes service excellence, with empowerment, is an important key for completing the job both efficiently and effectively.

SATISFACTION SCORES – Electricity customers' satisfaction

Top 2 Boxes: 'very + fairly satisfied'	**Welland Hydro**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	97%	92%	90%
POST: End of Interview	98%	91%	90%

Base: total respondents with an opinion

A mutual correlation exists between employee and customer attitudes and loyalty. Employees who are trained well, have the right tools, and are focused on successful outcomes for customers contribute significantly to the customers' perception of their utility. There is a direct, irrefutable link between empowered and engaged employees and customer satisfaction – after all -- *your employees are part of your brand, and they deliver the promises you make.*

Satisfaction With Welland Hydro By Key Segments

SATISFACTION SCORES – Electricity customers' satisfaction		
Top 2 Boxes: 'very + fairly satisfied'	**Residential**	**Small Commercial**
Satisfaction Scores	96%	100%

Base: total respondents with an opinion

SATISFACTION SCORES – Electricity customers' satisfaction [Income]			
Top 2 Boxes: 'very + fairly satisfied'	**<$50K**	**$50 – 74.9K**	**$75K +**
Satisfaction Scores	94%	98%	97%

Base: total respondents with an opinion

SATISFACTION SCORES – Electricity customers' satisfaction [Worry Paying Bill]				
Top 2 Boxes: 'very + fairly satisfied'	**Not a worry**	**Sometimes a worry**	**Often a problem**	**Depends**
Satisfaction Scores	98%	97%	79%	96%

Base: total respondents with an opinion

Customer Service

As written in previous years, given the rapidly expanding availability and use of technology, finding an appropriate balance between automated self-service and human-interactive service is a huge challenge for all involved in providing service to customers. Customer Service is about the experience your customers have with your utility, your products, and your service – regardless of the channel used for delivering customer service. The goal is to ensure that your customers receive high-quality customer service and an experience that meets or exceeds their expectations - on every interaction with the LDC.

Given the increased complexity of delivering customer service, we have seen a shift towards a stronger focus on the touchpoints which create the customer experience.

Most of us want the same things when we are customers: We want to be treated with respect. We want to be listened to. We don't want to be bounced around or ignored, or treated as inferior. The customer experience is largely defined by the outcomes generated when customers have a need, want to solve a problem, or want answers to issues or concerns they face.

With more technology, there will be more shifting of calls away from the call centre. However, the volume of calls that remain are and will be more complex and challenging. We're already witnessing the fact that calls are taking longer to deal with customer issues.

Customers are more concerned about outcomes, and they want their issue, problem, or concern to be dealt with in a professional, knowledgeable, and timely manner. Respondents were asked about six aspects of their most recent experience with a representative from Welland Hydro.

- Information – the quality of the information provided
- Staff attitude – the level of courtesy
- Professionalism – the knowledge of the staff
- Delivery – helpfulness of the staff
- Timeliness – the length of time it took to get what they needed
- Accessibility – how easy it was to contact someone

Customers are generally satisfied with their experiences dealing with Welland Hydro's customer service team. Many feel that it takes too much time to contact someone and for someone to deal with their problems.

Base: respondents contacting utility; small sample size

Satisfaction with Customer Service

Top 2 Boxes: ‘very + ‘fairly satisfied’	Welland Hydro	National	Ontario
The time it took to contact someone	76%	72%	63%
The time it took someone to deal with your problem	73%	70%	66%
The helpfulness of the staff who dealt with you	78%	76%	71%
The knowledge of the staff who dealt with you	89%	81%	75%
The level of courtesy of the staff who dealt with you	92%	87%	81%
The quality of information provided by the staff who dealt with you	76%	79%	75%

Base: respondents contacting utility, small sample size

Overall satisfaction with most recent experience

	Welland Hydro	National	Ontario
Top 2 Boxes: ‘very + ‘fairly satisfied’	76%	77%	71%

Base: respondents contacting utility, small sample size

Overall satisfaction and all detailed metrics for Welland Hydro are higher than the Ontario benchmark. Every interaction with a customer is an opportunity to generate higher levels of affinity. It is fool-hardy to view the ratings shown above as ratings for the “call-centre” because every person in Welland Hydro interacts with a customer or supports those who do have person-to-person contact with a customer. Empowerment is the backbone of the service recovery principle. In the face of error or problems, acting quickly and decisively, being empowered, and turning a dissatisfied customer into a satisfied one tends to have a positive impact.

Customer Focus – Service Quality

Current measures in the LDC scorecard are: New Residential Services Connected on Time; Scheduled Appointments Met on Time; and Telephone Calls Answered on Time. These are good examples of efficiency measures, as all are time-based. Showing up on time may not create satisfaction (in fact, it is what is expected); not showing up on time will cause dissatisfaction.

UtilityPULSE findings from working with many LDCs over the past few years indicate it is much harder to get great ratings from customers who may not know much about their LDC's standards for service. Despite this, service quality ratings for Welland Hydro are very good compared to the Ontario benchmark. Other dimensions of Service Quality that customers value include:

Core Customer Service Quality Attributes

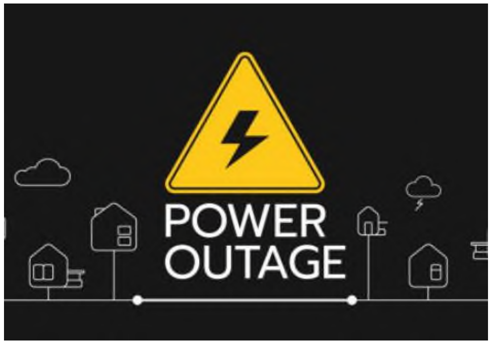
	Welland Hydro	National	Ontario
Customer-focused and treats customers as if they're valued	86%	78%	77%
Deals professionally with customers' problems	90%	81%	80%
Is pro-active in communicating changes and issues	85%	79%	78%
Delivers on its service commitments to customers	91%	83%	83%
Is 'easy to do business with'	89%	82%	82%
Adapts well to changes in customer expectations	84%	77%	75%

Base: total respondents with an opinion

We live in an imperfect world, so mistakes are bound to happen. In the LDC world, not all customer problems are mistakes; some are externally driven. Nonetheless, customers expect professionalism when interacting with "their" LDC.

Bill Payers' Problems and Problem Resolution

As previously written over multiple years, we call blackouts (outages) and billing problems the "Killer B's," the two issues most likely to cause grief to utility customers.



At one time, if the power went off for a few minutes, it was considered annoying and inconvenient. However, for most people, a power outage is now unbearable with the onset of computers and smart appliances in homes and businesses. Customers have little tolerance for an interruption in their flow of electricity.

27% of Welland Hydro respondents claimed they experienced an outage problem in the past 12 months, which is lower than the previous few years.

Like it or not, there will be times when the power goes off – and for reasons beyond the control of the LDC.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	Welland Hydro	National	Ontario
2022	27%	43%	48%
2021	-	39%	36%
2020	42%	40%	43%
2019	-	44%	45%
2018	32%	39%	44%

Base: total respondents / (-) not a participant of the survey year

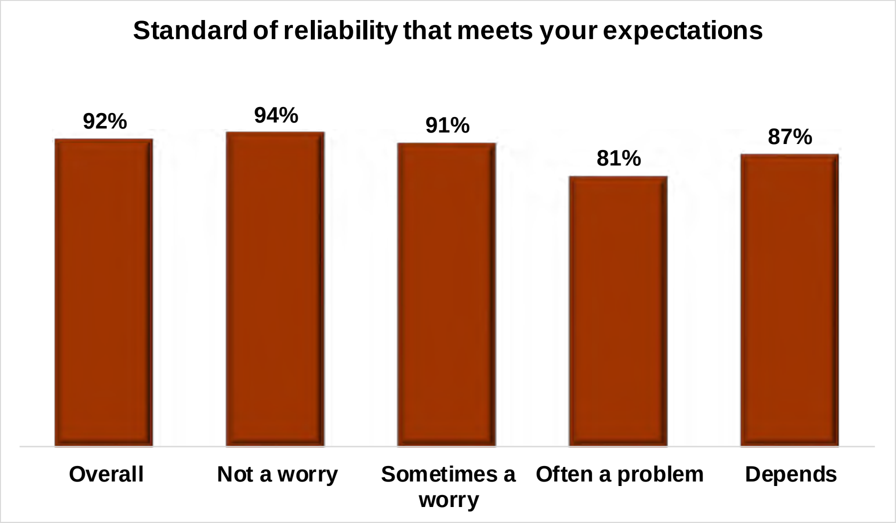
Perception of Outage Frequency			
	Welland Hydro	National	Ontario
Decreasing	14%	10%	8%
Increasing	7%	17%	22%
Staying the same	61%	66%	63%
Don't know	17%	6%	7%

Base: total respondents

How many outages have you had in the last 12 months	
	Welland Hydro Hydro
One	9%
Two	16%
Three	34%
More than three	32%

Base: respondents who experienced an outage

92% of Welland Hydro respondents believe the utility's standard of reliability is consistent with their expectations. Those who are more concerned with how they will pay their electricity bill each month are more negative about reliability of service.



Base: total respondents with an opinion

For nearly every business, the simple act of collecting payments from customers is quite complex. Organizations want to make it easy and convenient for customers to pay, so they offer multiple choices of payment types and channels. However, making it easy for the customer often makes it more complex—and costly—for the business and is certainly not without its problems or flaws.

Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	Welland Hydro	National	Ontario
2022	5%	10%	13%
2021	-	4%	6%
2020	4%	5%	6%
2019	-	9%	9%
2018	6%	9%	9%

Base: total respondents / (-) not a participant of the survey year

The impact of poor billing on a utility's business is considerable in terms of costs incurred handling customer queries and complaints. The quality of billing remains a driving force behind managing customer satisfaction and can help utilities reduce costs associated with customer service. By reducing the total number of calls to a utility by providing accurate, easily understood bills, a utility stems the flow of billing-related complaints into its call-centre. However, customers have a different definition than their utility as to what constitutes a billing problem.

Main Types of Billing Problems

	Welland Hydro
Online issues (e.g., unable to sign in)	30%
Wrong information on the bill	20%
The amount was too high	20%
The bill arrived late	15%
Complaint or inquiry about rates or charges	15%
Pricing was difficult to understand	10%
The bill was difficult to understand	5%
How the bill is calculated was difficult to understand	5%
Did not receive my bill/ebill/email notification	5%

Base: those who experienced a billing issue, small sample size

Beyond blackouts and billing issues, some also experienced other issues, primarily maintenance or repair requests (62%), online account setup issues (14%), service complaints (14%), and information changes (10%).

56% of Welland Hydro respondents visited the utility website to try on their own to either resolve or get more clarity on the issue of concern before attempting to contact the utility.

Did you try to contact your electric utility about any issues over the past 12 months?

38%

59%

Base: total respondents

How many times did you contact your utility?

	Welland Hydro
One	37%
Two	28%
Three	7%
More than three	21%
Don't know	7%

Base: respondents contacting utility, small sample size

- 59% of Welland Hydro respondents contacted the utility about an **outage problem**;
- 27% of Welland Hydro respondents contacted the utility about a **billing problem**;
- 28% of Welland Hydro respondents contacted the utility about a **problem other billing or an outage**.

Communication methods used to contact local utility	
	Welland Hydro
Telephone	75%
Email	28%
The utility’s website	7%
Social media i.e. Twitter, Facebook	1%
Mail	0%
In-person	12%
Live Chat	0%

Base: respondents contacting utility, small sample size

First Contact Resolution (FCR) rates are an important metric for improving call center performance. The first step in improving “FCR” is to survey your front-line customer touchpoints and understand what kind of assistance and information customers are seeking in these situations. Once you clearly understand what kinds of interactions are taking place at each of your initial customer touchpoints, you can then improve those interactions.

Percentage of Respondents who contacted their utility and had their problem solved in the last 12 months	
	Welland Hydro
Yes	60%
No	37%

Base: respondents contacting utility, small sample size

Communication When There is an Issue

Utilities need to know what response they are seeking from customers when planning their communications and outreach. Sending inserts with monthly bills that provide information to a customer is passive and not very effective. Although your customer audience is captive, a poorly targeted message is often ignored. Unless a customer is actively searching for it, posting information on a website will likely not be found. Email blasts and social media campaigns will reach customers but may not necessarily lead to action. Such messages are typically read when in transit or multitasking, making them an afterthought. So, it often takes several pushes for these messages to resonate before action is taken. Successful marketing and messaging are about keeping communications simple, consistent, and continually reinforced.

Effective communication is essential to provide good customer service, improve efficiency and reduce costs. LDCs must maximize the effectiveness of their communications and improve customer interactions consistently across some media channels and customer touch points.

Preferred Communication Channels for Unexpected Outages

In times of emergency, be they extreme weather events or major equipment failures that cause blackouts and unplanned outages, customer communication can help customers understand what to expect next and when disrupted electricity service might be restored. Early and effective communication helps increase confidence in and credibility of the electricity service provider.

Respondents were asked the preferred communication channels Welland Hydro should use ***during an unexpected outage.***

Preferred method of communication Welland Hydro should use during an UNEXPECTED Outage

	Welland Hydro
Text message alert	68%
Email alert/notice	51%
Recorded telephone message alert	28%
A toll-free or call-in outage line	25%
Social media alert	23%
Other	6%
Don't recall / Don't know	1%

Base: total respondents

LDCs, for the most part, are primarily set up as “inbound” problem solvers and communicators. The notion or idea that the LDC needs to become more “outbound” with personalized channel communication is a challenge from an organizational culture and operations perspective. Yet, if the LDC doesn’t become more outbound driven, it will have to invest more into inbound methods for solving problems – which is extremely expensive.

Our data from the past several years show “older” respondents have a heavier desire to communicate via the telephone, but youths, especially those in the 18-34 range, are far more comfortable getting and receiving information electronically. Preferences are changing.

While there are many ways to communicate, information and messaging are most effective when delivered through channels preferred by customers, and the LDC’s messaging should be simple, clear, fact-based, and consistent.

Welland Hydro must understand how customers communicate with you and how they would like Welland Hydro to communicate with them in the future. Knowing this will allow Welland Hydro to: allocate resources where they are most needed, tailor services to meet customers’ needs; and, identify where improvements can be made.

Interest in Communication Options From Welland Hydro

Top 2 Boxes: ‘very + somewhat important’	Welland Hydro
E-billing (paperless option)	89%
Request for call back on website	82%
Email (including e-blasts)	80%
Telephone	80%
Ability to receive updates via SMS/text	67%
Live chat on website	63%
Letter mail	48%

Base: total respondents with an opinion

However, while most customers appear to have the capacity and willingness to use digital channels, some customers do not access digital platforms for a variety of reasons, such as a lack of ability or resources or due to a preference for other channels. Welland Hydro will need to consider how these customers can be supported and encouraged to use digital services in the future.

Digital exclusion – some people may not have access to the internet at home, which may mean they would not have access to information and services online. However, most government entities recognize the importance of internet access. These past couple of challenging years have pushed the older demographic to embrace technology much faster. Also, there is an age bias toward the use of technology. Welland Hydro needs to continue to recognize that while electronic access is growing, the need to maintain traditional access systems remains real. Providing customers with clear, easy-to-access services and information which is easy to understand has a significant impact on the customer experience.

When customers have a high level of satisfaction with access to services, it is much easier for LDCs to forge a new kind of relationship with its customers, which, in turn, helps all parties successfully deal with the issues and opportunities of the new energy world.

Satisfaction with Education and Information

Important issues are being communicated well to Welland Hydro customers and most are satisfied with the information they've received.

Satisfaction With Education and Information Received From Welland Hydro

Top 2 Boxes: 'very + fairly satisfied'	Welland Hydro
The quality of information about the various payment options available to you, such as equal payment options, pre-authorized automated payments, or e-billing	92%
The electricity safety education provided to the public	91%
The timing of information for things such as planned outages, construction activity, tree-trimming	91%
Regulated changes in regards to rates, customer service rules and programs	88%
The quality of information about the two different rate options available to you, referred to as Tiered Pricing and Time-of-Use pricing	85%
The quality of information available when outages occur	84%
The quality of information about the various payment options available to you, such as equal payment options, pre-authorized automated payments, or e-billing	92%

Base: total respondents with an opinion

Priority Planning

Customers are impatient, employees are impatient, company leadership is impatient, we want everything ‘right now’ and at ‘no cost.’ Priority planning is about having a (reasonably) clear focus on what is important to customers or other stakeholders, and to help people from feeling overwhelmed. By engaging stakeholders and obtaining their input in undertaking a priority planning process helps to build "prepared minds"—that is, to make sure that the LDC decision-makers have a solid understanding of customer priorities, and what things the business might need to change or make investments in.

Respondents were asked to comment on the priority level of the implementation or execution of 12 different initiatives/projects which encompass operational aspects and/or financial commitment. The following numbers are based on your full survey; there are differences by age, income, or kWh usage.

A focus on priorities can lower risk, increase efficiency, and optimize resource utilization - resulting in faster deliveries of key requirements.

Priority Planning Within the Next 5 Years	
Top 2 Boxes: ‘very high + high priority’	**Welland Hydro**
Investing more in the electricity grid to reduce outages	97%
Preventing data breaches and system disruptions due to cyberattack	96%
Reducing response times to outages	96%
Educating the public as it relates to electricity safety	82%
Increasing the use of e-billing and paper-free communication options to reduce environmental impact and improve cost-effectiveness	79%
Providing more self-serve services on the website	62%
Increasing the use of social media (such as Twitter, Facebook, and others)	51%

Base: total respondents with an opinion

Customer Experience Performance rating (CEPr)

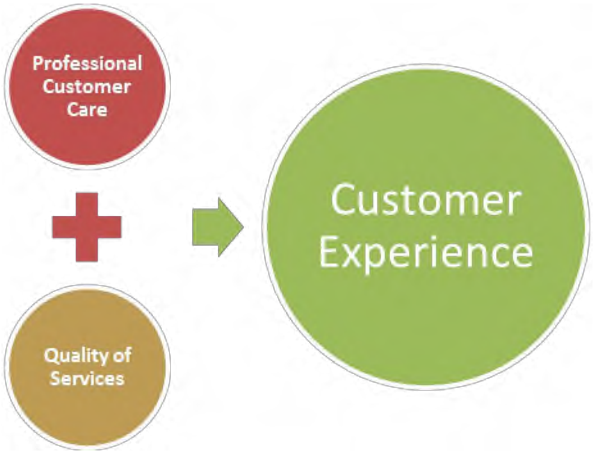
The CEPr score is an effectiveness rating and is affected by many dimensions of service. Every touchpoint with customers on the phone, website, or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience, the perception created is future transactions will be excellent too. Of course, a negative transaction creates the perception that future transactions will be negative.

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

Understanding your customer's expectations for service is the first step in providing an amazing customer experience. It is essential customer care call centres develop a comprehensive understanding of what

At the heart of the CEPr are 4 central questions:

1. *Are interactions with the organization professional and productive?*
2. *Is the organization 'easy to deal with'?*
3. *Does the organization effectively meet your needs?*
4. *Does the organization provide high quality services?*



customers expect from them, whether their needs are being met and how they can improve their service to meet their expectations.

Some of the factors which contribute to the overall customer experience:

- Delivering accessible and consistent customer service (multi-channel)
- Understanding customer expectations
- Maintaining timely resolution timelines
- Providing effective communication(s) according to customer needs
- Demonstrating responsiveness
- Speeding up problem resolution
- Conducting problem analysis to prevent recurring issues
- Easy to do business with
- Seeking customer feedback and following through on recommendations

Customer Experience Performance rating (CEPr)

	Welland Hydro	National	Ontario
CEPr: all respondents	90%	83%	82%

Base: total respondents

The CEPr for Welland Hydro is 90%. This rating would suggest that a very large majority of customers have a belief they will have a good to excellent experience dealing with Welland Hydro professionals.

Customer Centric Engagement Index (CCEI)

Customer engagement and customer satisfaction are very different measures. We believe generating high scores in customer engagement is more difficult than customer satisfaction. For example, a customer can be highly satisfied when the LDC reliability delivers electricity, bills the customer properly, and quickly deals with outages. Essentially when the LDC does what it promises to do, then satisfaction follows.

Customer engagement is about connecting with customers to demonstrate that the LDC has heard the customer and understands the customer's needs, wants, desires, and issues. When the LDC does demonstrate listening and understanding, the result is higher levels of emotional connection, i.e., feelings that the people at the LDC care, respect, and value their customers or are prepared to go-out-of-their-way (if necessary) to help.

Customer engagement is often thought of as a series of activities involving the customer, such as conducting a survey, holding town hall type meetings, focus groups, etc. One could call these types of activities as the behaviour side of engagement. However, there is an emotional side to engagement.

UtilityPULSE has identified the six key dimensions of what defines customer engagement. They are: empowered, valued, connected, inspired, future-oriented, and performance-oriented. Customer-centric engagement is a measure of “goodwill” towards the utility. The UP% database does show Secure customers believe they are more highly engaged with their LDC than customers who are At Risk.

This survey also provides you with an emotional look at engagement. The UtilityPULSE CCEI is a gauge of the amount of goodwill which has been generated. High numbers in CCEI suggest there is a high level of goodwill amongst your customers – this is important for two reasons. First, when something goes awry for the utility, goodwill helps the utility to be resilient. Second, goodwill encourages active participation in requests to participate in engagement activities or program offerings from the utility.

The CCEI is a metric designed to get a more in-depth look at the attachment a customer has with your LDC and its brand. High levels of customer engagement (emotional) correlate strongly to high levels of Secure and Favourable customer numbers.

Engagement is how customers think, feel, and act towards the organization. As such, ensuring customers respond positively requires they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization.

Utility Customer Centric Engagement Index (CCEI)

	Welland Hydro	National	Ontario
CCEI	88%	81%	80%

Base: total respondents

As measured by the CCEI, less engaged customers are more likely to let costs and/or price impact their perceptions of their LDC. Customers who are highly engaged are more inclined to look past costs and money issues and use a rational approach to make values-based decisions. Highly engaged customers have a stronger emotional connection to your utility. It's this emotional connection that drives commitment, loyalty, and advocacy.

Using the measures of Satisfaction and Engagement, the LDC's relationship with its customers would fall into one of four quadrants: Q1- low satisfaction/low engagement; Q2- high satisfaction/low engagement; Q3- low satisfaction/high engagement and Q4- high satisfaction/high engagement. Most LDCs would agree that having customers fall into the Q1 quadrant isn't good and that customers falling into Q4 is ideal.

When LDCs have candid conversations with customers and employees about their joint and different needs & perspectives, the better the LDC can be for creating an excellent place to do business with and to work.

Customer Effort & Experience Score^{TM} (CEES)

Customers want the processes involved in solving problems or arranging service to be both fast and easy. For the most part, they already know they have a problem or need assistance, hence their dislike/displeasure when being transferred between people or departments, receiving a slow response, or receiving uncaring service. They also dislike "surprises," which is a potential reason why utilities are expected to be "pro-active communicators."

The more time and effort a customer exerts to get questions answered or problems solved, the less happy they are, and the more likely they are to view their LDC as incompetent or lacking in customer-focus.

The CEES as a metric is designed to help the organization remain focused on making things easy and fast for customers. The goal is to encourage improvements in all aspects of the customer's journey from initial contact to completion of the issue. The central idea of CEES is about getting the most from your investments in people and technology.

As Richard Sharpe, the CEO of Sears Canada during its heyday, said, “A little TLC goes a long way.” He meant that when everyone attempts to Think Like a Customer (TLC), good things happen.

What is the difference between CEES and First Call Resolution, i.e., Problem Solved?

First-call or First-contact resolution (FCR) is a focus and metric for LDCs. What the FCR doesn’t measure is the repeat or follow-up calls regarding the resolution to the problem. For example, a customer may have requested a particular service, and the CSR arranged it – the first time – within a timeline agreed upon by the customer. However, the customer may have additional follow-up questions regarding the requested service and will, therefore, contact the utility again.

The CEES metric helps the organization focus on making things easy and fast for customers by taking into account typical follow-up issues/calls that customers make. LDCs could make better use of processes such as auto dialing reminders of dates/times, emailing information about being prepared, what to do while the electricity is off when the crew is working, etc.

With every passing year, the shift away from phone service to self-service continues. Throwing forms and information on the website **isn’t** “self-service.” We believe LDCs should rebuild their organization around self-service and do so by making it “easy” and “fast” for customers to get information and solve problems.

The CEES is complimentary to the Net Supporter Score. In other words, improvements in CEES scores translate to improvements in Net Supporter Scores. Welland Hydro has rated a Customer Effort & Experience Score (CEES)^{TM} of 54%, and the Ontario benchmark is 23%, and the UtilityPULSE database average is 35%.

Customer Effort & Experience Score (CEES)			
	Opportunity Range <15%	**Good Range 15-34%**	**Very Good Range 35+%**
Welland Hydro			54%
National Benchmark		25%	
Ontario Benchmark		23%	
UP Database			35%

Base: total respondents; range bands represent 2022 data and can change year-to-year

The Customer Effort & Experience Score™ is about encouraging your people to figure out how to speed up and simplify interactions. It is designed to encourage dialogue with all areas of the business to reduce customer effort. Busy, time-pressed customers consider CEES a bona-fide reflection of the business. Most importantly, it has a direct correlation to customer satisfaction, loyalty, and NSS.

UtilityPULSE Report Card®

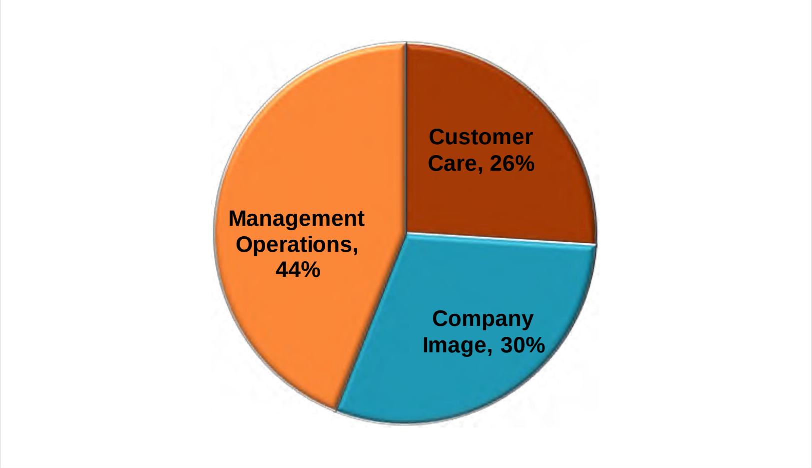
UtilityPULSE's Report Card® is based on tens of thousands of customer interviews gathered over many years. The purpose of the UtilityPULSE Report Card® is to provide electric utilities with a snapshot of performance – on the things customers deem to be important. Research has identified over 20 attributes, sorted into six topic categories (we call these drivers), which customers have used to describe their utility when they have been satisfied or very satisfied with their utility. These attributes form the nucleus, or base, from which "scores" are assigned. Customer satisfaction and loyalty also play a major role in the calculations.

There are two main dimensions of the UtilityPULSE Report Card®. The first is the customer psyche, and the other is customer perceptions about how the utility executes its business.

The Psyche of Customers

Every utility has virtually the same responsibility – provide safe and reliable electricity – yet not all customers are the same. The following chart shows the weight or significance of each category to the customer when forming their overall impression of the utility. Three major themes, each with two major categories, make up the UtilityPULSE Report Card®. In effect, the Report Card provides feedback about how customers perceive the importance of each category.

UtilityPULSE Report Card® Weighting



Base: total respondents

The UtilityPULSE Report Card® also provides customer perceptions about how your utility executes or performs its responsibilities. This is different, very different, from what a customer might say about a major concern or worry they have about electricity. Since its inception, our survey has shown that the primary suggestion for improvement is "reduce prices," which is also a major concern that your customers have about municipal taxes, gas for the vehicle, and other utilities.

Readers of this report should note that the categories and drivers are interdependent. This means, for example, failure to provide high levels of power quality and reliability will have a negative impact on customer perceptions as it relates to customer service. Customer care, when it does not meet customer expectations has a negative impact on Company Image, etc.

Defining the categories and major drivers:

Category: Customer Care

Drivers: Price and Value; Customer Service

Just because everyone likes good customer care, that in and by itself is not a reason to provide it – though it may be important to do so. In highly competitive industries, good customer service may be a differentiating factor. The case for electric utilities is simple, high levels of customer care result in less work (hence cost) of responding to customer inquiries and higher levels of acceptance of the utility's actions.

Price and Value:

Customers have to purchase electricity because life and lifestyle depend on it. This driver measures customer perceptions as to whether the total costs of electricity represent good value and whether the utility is seen as working in the best interests of its customers as it relates to keeping costs affordable.

Customer Service:

Customers do have needs, and every now and again will interact with their utility. How the utility handles various customers' requests and concerns are what this driver is all about. Promptly answering inquiries, providing sound information, keeping customers informed, and doing so in a professional manner are the major components of this driver.

Category: Company Image

Drivers: Company Leadership; Corporate Stewardship

Utilities have an image even if they do not undertake any activities to try to build it. A company's image is both a simple and complex concept. It is simple because companies do create images that are easily described and recognized by their target customers. It is complex because it takes many discrete elements to create an image, which includes, but is not limited to: advertising, marketing communications, publicity, service offering, and pricing.

An electric utility trying to manage its image has one more challenge to deal with, and that is the electric industry itself. There are so many players; residential customers (in particular) don't know who does what or who is responsible for what. So, when there are political or regulatory announcements, the local utility is often swept up into the collective reaction of the population.

Company Leadership

This driver is comprised of customer perceptions as it relates to industry leadership, keeping promises, and being a respected company in the community.

Corporate Stewardship

Customers rely on electricity and want to know their utility is both a trusted and credible organization that is well managed, accountable, socially responsible, and has its financial house in order.

Category: Management Operations

Drivers: Operational Effectiveness; Power Quality and Reliability

Electrical power is the primary product utilities provide their customers. Customers have very high expectations that the power will be there when they need it. Customers have little tolerance for outages. The reality is, every utility must get this part right…no excuses. It is the utility's core business. This category and its drivers are the most important for fulfilling the rational needs of a utility's customers.

Operational Effectiveness

This driver measures customers' perceptions as they relate to ensuring their utility runs smoothly. Attributes such as accurate billing and meter reading, completing service work in a professional and timely manner, and maintaining equipment in good repair are deemed important to customers.

Power Quality and Reliability

Power outages are a fact of life – and customers know it. They expect their utility to provide consistent, reliable electricity, handle outages, restore power quickly, and make using electricity safely an important priority.

Welland Hydro's UtilityPULSE Report Card®

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

Base: total respondents

As the UtilityPULSE Report Card® shows, the total customer experience with an electric utility is defined as more than "keeping the lights on." Customers deal with your utility every day for a variety of reasons, most likely because they need someone to help them solve a problem, answer a question, or take their order for service. All your employees, from customer service representatives to linemen, leave a lasting impression on the customers they interact with. In effect, there are many moments of truth. Moments of truth are every customer touchpoint a utility has with its customers. Therefore, managing these moments of truth creates higher levels of Secure customers while reducing the number of At Risk customers that exist.

It's the small things done consistently that matter: Things like greeting every customer, whether on the phone or in person, in a friendly and helpful manner. Things like listening to the customer's needs, providing solutions to their problems, and showing appreciation for their business.

Utilities now recognize customer communications as a valuable aspect of their business. The better a utility communicates with customers in a manner that speaks to them; the more satisfied they are with their overall service. “Sending out information” is not the same as having a “conversation” with a customer. We believe it is increasingly important to channel your communications to the various customer segments which exist.

Employees – in every area – play a critical role in customer service success. Consequently, how they feel about their job responsibilities and role in the company will be communicated indirectly through the level of service they provide customers with. The reality is engaged employees are the key to excellent customer care.
Our survey work with employees shows there are many elements of organizational culture to support the people model needed to achieve high levels of engagement.

Our research has identified 6 main drivers which promote and support people giving their best:

People Model

- **Empowered**
- **Valued**
- **Connected**
- **Inspired**
- **Growing**
- **Performance oriented**

There are 12 key processes from “attracting employees” to “saying goodbye to employees” are part of your people model to get the best performance from every employee.

We believe taking the time to understand the difference between employee satisfaction and organizational culture is worthwhile from a resourcing perspective and a people development perspective. Every organization has a culture – we believe it is a leadership imperative to install and maintain a culture which ensures you attain the achievements and successes of your utility’s many investments in people, technology, and equipment. It is true, organization culture affects everyone, and everyone affects organization culture.

The Loyalty Factor

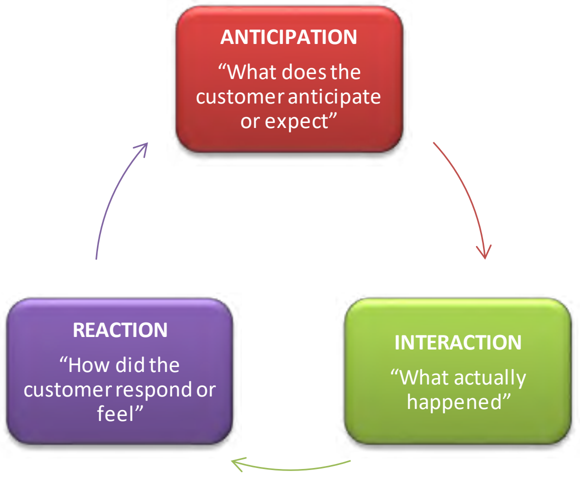
If a customer is satisfied, it doesn't necessarily mean they are loyal. Satisfaction is about fulfilling promises/expectations; loyalty goes way beyond that by creating exceptional experiences and long-lasting relationships. There is a reason why marketing campaigns strive to build brand loyalty, not brand satisfaction. Measuring customer loyalty in an industry where many customers don't have a choice of providers doesn't make sense. Or does it?

The answer depends on how you define "customer loyalty."

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, the customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at-risk" is not about their future behaviour but more about their "attitudinal" loyalty (are they advocates?).

Customer Service, when done well, promotes satisfaction which builds the foundation towards loyalty. Whether a customer is loyal and/or satisfied will be determined by three realities: ANTICIPATION – what your customer anticipates or expects; INTERACTION – what actually happened with/to the customer; and REACTION – how did the customer respond and how did it ultimately make the customer feel.



Perhaps a better or more relevant way for utilities to approach the definition of customer loyalty is to expand further how they think about loyalty. Consider the following definition: Customer loyalty is an emotional disposition on the part of the customer, which affects the way(s) in which the customer (consistently) interacts, responds, or reacts towards the company – its products & services, and its brand.

Some Tips to build loyalty:

- ✓ **Solve problems quickly**
- ✓ **Treat customers right**
- ✓ **Listen to complaints**
- ✓ **Be personal; create a great experience**
- ✓ **Friendly customer service**
- ✓ **Accessible information or help**
- ✓ **Good reputation**
- ✓ **Demonstrate you care**

So, what does it mean to respond favourably to a company? At a basic level, this can mean choosing to remain a customer. As previously mentioned, however, this is essentially a non-issue for many utility companies. It then becomes necessary to think beyond just customer retention. One needs to consider other ways in which customers can respond favourably toward a company.

Other favourable responses or behaviours can be classified into one of three categories that reflect the concept of customer loyalty:

- Participation
- Compliance or Influence
- Advocacy

Specific examples of potential participatory behaviour in the electric utility industry include:

- Signing up for programs which help the customer reduce or manage their energy consumption
- Using the utility as a consultant when selecting energy products and services from a third party
- Participating in pilot programs or research studies.

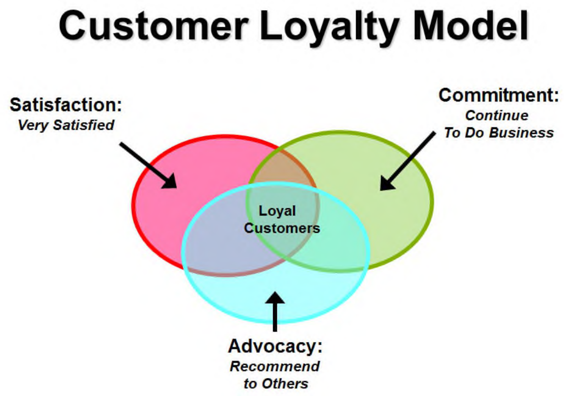
Specific examples of potential compliance or influence behaviours utility customers might exhibit include:

- Seeking the utility's advice or expertise on an energy-related issue
- Voluntarily cutting back on electricity usage if the utility advised the customer to do so
- Accepting the utility's energy advice or referrals to energy contractors or equipment
- Being influenced by the utility's opinion regarding energy- management advice, equipment, or technologies
- Providing personal information which enables the utility to serve the customer better
- Paying bills online.

Creating customer advocates can be especially important for a company in a regulated industry. In the absence of customer advocates, or worse, in a situation where customers speak unfavourably about a company or actively work to support issues that are counter to those the company supports, companies can suffer a variety of negative consequences like increased business costs, lawsuits, fines, and construction delays. For an electric utility, specific examples of potential advocacy behaviour include:

- Supporting the utility's positions or actions on energy-related public issues, including the environment
- Supporting the utility's position on the location and construction of facilities
- Providing testimonials about positive experiences with the utility

Loyalty is driven primarily by a company's interaction with its customers and how well it delivers on their wants and needs.



Loyalty is based on likelihood to:

- ***Satisfaction: overall satisfaction***
- ***Commitment: continue as a customer***
- ***Advocacy: willingness to recommend***

In sum, loyal behaviour in the utility industry may not be as evident as it is in a more competitive environment. Measuring customer loyalty in a generally non-competitive industry requires one to think about loyalty in non-traditional ways. Customer loyalty is an intangible asset with positive consequences or outcomes associated with it no matter what the industry. Properly measuring loyalty among utility customers requires thoughtful probing to thoroughly identify the range of participation, compliance, and advocacy behaviours that will ultimately benefit the company in meaningful ways and foster happier and more loyal customers.

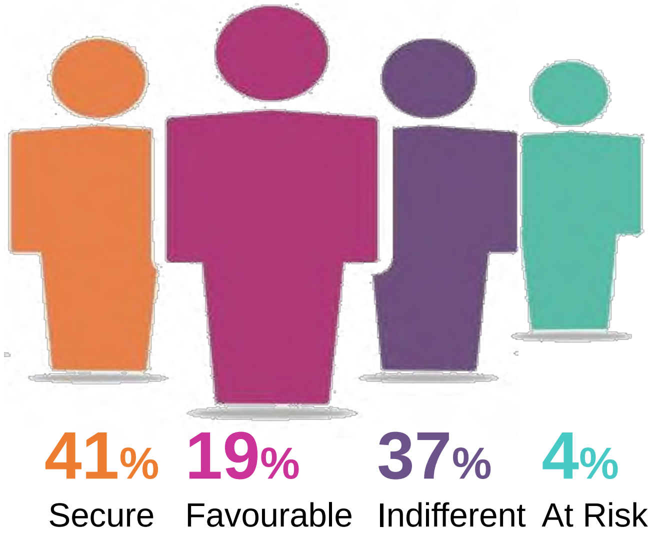
The UtilityPULSE Customer Loyalty Performance Score segments customers into four groups: **Secure** – the most loyal - **Still Favorable**, **Indifferent**, and **At risk**.

Secure customers are “very satisfied” overall with their local electric utility. They have a very high emotional connection with their utility and “definitely” would recommend their local utility.

Still favorable customers are “very satisfied” overall, “definitely” or “probably” would recommend their local utility and not switch if they could.

Indifferent customers are less satisfied overall than secure and still-favorable customers and less inclined to recommend their local utility or say they would not switch.

At risk customers, who are “very dissatisfied” with their electric utility, “definitely” would switch and “definitely” would not recommend it.



Customer Loyalty Groups – Welland Hydro

	Secure	Favorable	Indifferent	At Risk
2022	41%	19%	37%	4%
2021	-	-	-	-
2020	39%	19%	38%	5%
2019	-	-	-	-
2018	41%	15%	38%	6%

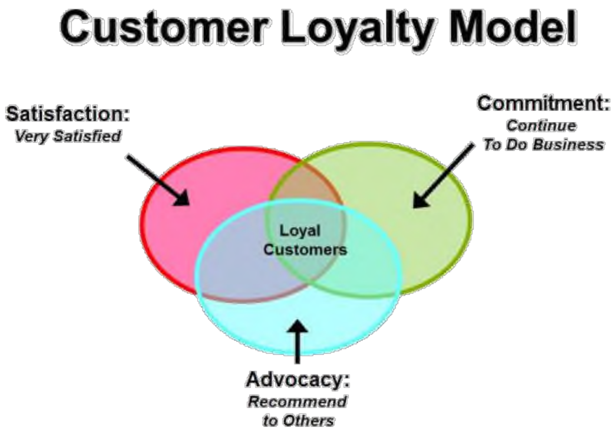
Base: total respondents / (-) not a participant of the survey year

Customer Loyalty Groups				
	Secure	**Favorable**	**Indifferent**	**At Risk**
Ontario				
2022	21%	18%	54%	6%
2021	28%	16%	48%	8%
2020	29%	20%	46%	6%
2019	27%	16%	48%	9%
2018	20%	16%	50%	13%
National				
2022	19%	17%	57%	8%
2021	29%	17%	47%	7%
2020	30%	18%	48%	5%
2019	27%	17%	49%	7%
2018	24%	15%	51%	10%

Base: total respondents

Customer Commitment

Customer loyalty is a term used to embrace a range of customer attitudes and behaviours. One of the metrics used to gauge loyalty is the measure of **retention,** or intention to buy again; this loyalty attitude is termed **commitment.** For LDCs, commitment is not about behaviour; it is about attitude, i.e., do they want to remain your customer.



Customer commitment is a very important driver of customer loyalty in the electricity service industry. In a similar way to trust, commitment is considered an important ingredient in successful relationships. In simpler terms, commitment refers to the motivation to continue to do business with and maintain a relationship with a business partner, i.e., the local utility.

For electric utilities, this measurement is about identifying the number of customers who feel they “want to” vs. “have to” do business with you. Potential benefits of commitment may include word of mouth communications - an important aspect of attitudinal loyalty. Committed customers have been known to demonstrate several beneficial behaviours; for example, committed customers tend to:

- Come to you. One of the key benefits of establishing a good level of customer loyalty is customers will come to you when they need a product or service

- Validate information received from 3rd parties with information and expertise that you have
- Try new products/initiatives
- Perhaps they will even trust you when recommendations are made
- Be more price tolerant
- More receptivity of utility viewpoints on various issues
- More tolerance of errors or issues which inevitably take a swipe at the utility
- Stronger levels of perception regarding how the utility is managed.

Though customers cannot physically leave you, they can emotionally leave you, and when they do, it becomes an extreme challenge to garner their participation or support for utility initiatives.

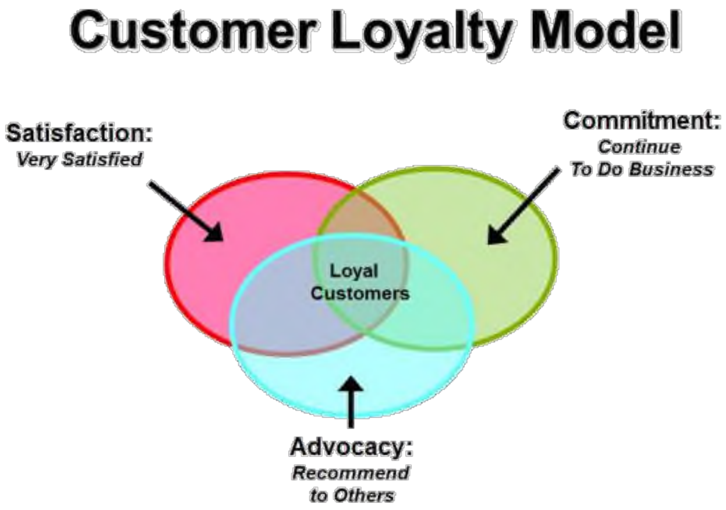
Electricity customers' loyalty – … Is a company that you would like to continue to do business with

	Welland Hydro	National	Ontario
Would continue to do business	91%	84%	82%

Base: total respondents with an opinion

Word of Mouth

Advocacy is one of the metrics measured in determining customer loyalty. Essentially, companies believe a loyal customer is one who is spreading the value of the business to others, leading new people to the business, and helping the company grow. Customer referrals, endorsements, and spreading the word are extremely important forms of customer behaviour. For LDCs, this is about generating positive referents about the LDC as a relevant and valuable enterprise.



When customers are loyal to a company, product, or service, they are not only more likely to purchase from the company again, but they are more likely to recommend it to others – to openly share their positive feelings and experiences with others.

In today's world, thanks to the Internet, they can tell and influence millions of people. The same holds true, if not more so, when customers are disloyal. Disgruntled customers could share their negative experiences with an ever-widening audience, jeopardizing a company's reputation and resulting in fewer engaged customers and/or customers who are Favourable or Secure. Secure customers typically are advocates, and they are deeply connected and brand-involved.

Word of mouth communication is a potent form of communication and influence. When customers speak to other customers (or their peers), it is more credible; it goes through fewer perceptual filters and can enhance the view of services or products better than marketing communication.

There are two forms of word of mouth which utilities need to understand. The first is ***Experience-based word of mouth*** *which is the most common and most powerful form. It results from a customer's direct experience with the utility or the re-statement of a direct experience from a trusted source.*

The second is ***Relay-based word of mouth****. This is when customers pass along important messages to others based on what they have learned through the more traditional forms of communications. For example, if the utility was communicating an offer for "free LED lights" chances are high the offer will be "relayed" to others through word of mouth.*

For an electric utility, specific examples of potential positive advocacy behaviour include:

- *Recommending other customers specifically locate in the geographic area which is serviced by that utility*
- *Supporting the utility's positions or actions on energy-related public issues, including the environment*
- *Supporting the utility's position on the location and construction of facilities*
- *Providing testimonials about positive experiences with the utility*

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague

	Welland Hydro	National	Ontario
Is a company you would recommend	89%	80%	78%

Base: total respondents with an opinion

Electricity customers' loyalty – is a company that you would recommend to a friend or colleague

Welland Hydro	2022	2021	2020	2019	2018
Is a company you would recommend	89%	-	88%	-	-

Base: total respondents with an opinion / (-) not a participant of the survey year

Our survey research, as well as theory, backs up the fact that if your customers are willing to endorse you and put their reputation on the line to recommend you, they also trust you and are satisfied with the service you are providing.

Net Supporter Score (NSS) vs. Net Promoter Score (NPS)

The Net Supporter Score^{TM} (NSS) is a metric which measures how likely customers could ***support*** policy changes, actions, programs, or service changes or enhancements the LDC wishes to make. The NSS is a metric developed to help the organization and its people continue on a path of improving customer experiences, whether those experiences are in-person, over the telephone, or online. In a nutshell, the NSS reflects the net number of customers who have confidence in the LDC to continue to serve in their best interests.

Supporter

In a world where technology, societal, legislative, and regulatory changes can happen quickly, utilities need to adapt and respond professionally without causing customer disruption. Supporters may not “like” a change, but they are more likely to “support” the change because they believe the utility is operating in the best interests of all parties.

Net Supporter Score^{TM} (NSS)			
	Opportunity Range <10%	Good Range 10-19%	Very Good Range 20+%
Welland Hydro			36%
Ontario Benchmark		11%	

Base: total respondents; range bands represent 2022 data and can change year-to-year

Welland Hydro has a Net Supporter Score^{TM} (NSS) of 36%**.**

The Ontario benchmark is 11% and the UtilityPULSE database average is 20%.

The Net Promoter Score™ (NPS) is a well-known measurement that is respected for its simplicity and tendency to help an organization and its people focus on customer experiences. For utilities, customers with a high net promoter score may be good candidates for increased outreach and offer demand response and other utility programs. In a sense, it is a complementary measure to the well-established loyalty measure we call “Secure” customers.

Promoter

Nonetheless, the NPS is an easy calculation and is based on the score of one question. That question is about the subject of “recommend to others.” The NPS was designed to help companies sell more products and services. For utilities, the NPS is best suited as an affinity gauge. Like other measures, Satisfaction, Loyalty, CEES, CEPr, NSS, and others, NPS is another measure that can promote internal dialogue about how processes, policies, and service can evolve so that more customers would “recommend” the utility.

The NPS metric was developed by and is a registered trademark of Fred Reichheld, Bain & Company, and Satmetrix in 2003.

Welland Hydro has a Net Promoter Score^{TM} (NSS) of 58%**.** The Ontario benchmark is 21%, and the UtilityPULSE database average is 37%.

Net Promoter Score^{TM} (NPS)			
	Opportunity Range <5%	**Good Range 5-24%**	**Very Good Range 25+%**
Welland Hydro			58%
Ontario Benchmark		21%	

Base: total respondents; range bands represent 2022 data and can change year-to-year

Corporate Image

Although reputation is an intangible concept, a strong corporate image makes it easier to capture the attention of more customers – more often. Also, to be seen as an independent organization, thereby making it easier to introduce new ideas. Employees appreciate a strong corporate image.

Attributes measured in the annual UtilityPULSE survey which are strongly linked to a utility's image include:

Attributes linked to Company Image and Reputation

	Welland Hydro	National	Ontario
Keeps its promises to its customers and community	90%	81%	80%
Adapts well to changes in customer expectations	84%	77%	75%
Pro-active in communicating changes and issues which may affect service	85%	79%	78%
Customer-focused and treats customers as if they're valued	86%	78%	77%
Spends money prudently to keep the electricity system reliable	85%	78%	77%
Is a socially responsible company	89%	80%	79%
Company to recommend	89%	80%	78%
Delivers on its service commitments	91%	83%	83%
Is 'easy to do business with'	89%	82%	82%
Operates a cost-effective electricity system	81%	74%	70%
Is a trusted and trustworthy company	90%	83%	82%

Base: total respondents with an opinion

Corporate Credibility & Trust

Credibility is a judgment customers and others make about whether a person or an organization has the competencies and experience to do what they promise to do. Trust is a feeling or belief that a person or an organization they are dealing with is doing so in an honest, open manner with no hidden agendas. How customers and other stakeholders respond to your communications is affected by the person's perception. Without credibility and trust, everything you say to customers, employees, and others can be questioned.

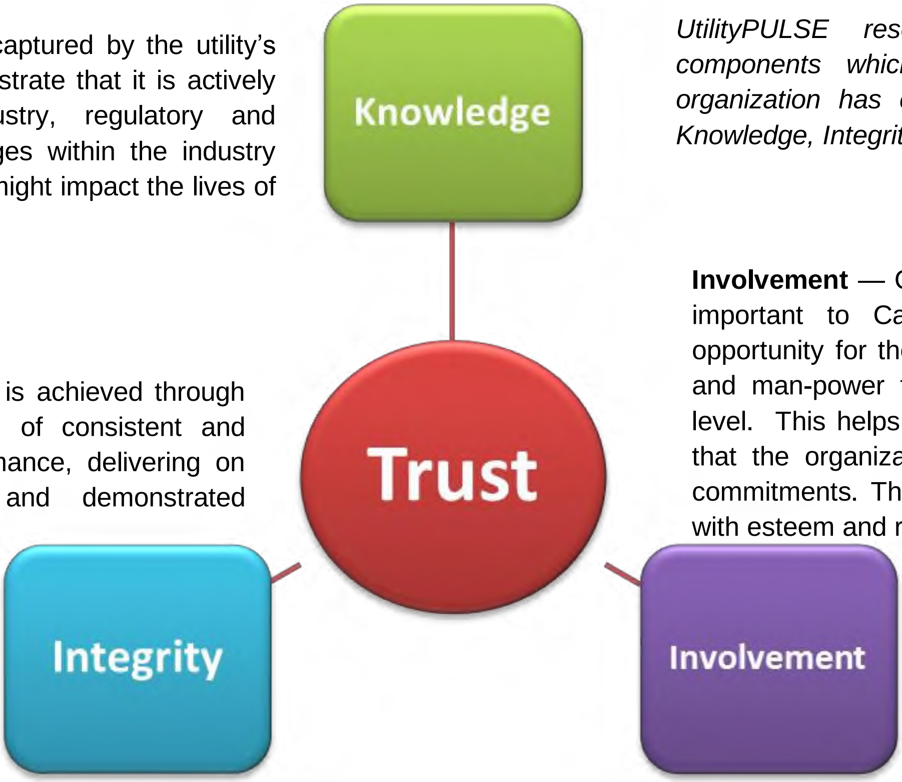
Of paramount importance to maintaining credibility & trust is effectively managing expectations—customers, employees, and other stakeholders that matter to the business of the LDC. A key to this is open and honest communications. An important benefit of having a high degree of credibility & trust is, authentic collaboration can become a reality. Credibility & trust is a powerful currency for building relationships. Credibility & trust are outcomes based on what the LDC does, not what it might be doing.

Attributes strongly linked to Credibility & Trust

	Welland Hydro	National	Ontario
Efficiently manages the electricity system	90%	82%	81%
Keeps its promises to customers and the community	90%	81%	80%
Customer-focused and treats customers as if they're valued	86%	78%	77%
Is a trusted and trustworthy company	90%	83%	82%

Base: total respondents with an opinion

UtilityPULSE research shows the under-pinning components which lead customers to believe an organization has credibility and can be trusted are: Knowledge, Integrity, Involvement and Trust.



Knowledge is captured by the utility's ability to demonstrate that it is actively aware of industry, regulatory and economic changes within the industry and how these might impact the lives of customers.

Trust — Trust is achieved through a track record of consistent and reliable performance, delivering on commitments and demonstrated accountability.

Involvement — Corporate Involvement is increasingly important to Canadian communities as it is an opportunity for their local utility to use their resources and man-power to benefit people at the community level. This helps to build credibility as customers see that the organization is acting and delivering on its commitments. This helps customers regard the utility with esteem and respect.

Integrity is established by demonstrating adherence to a code of conduct. It requires consistently acting in accordance with the values and goals that have been communicated to customers.

Credibility and Trust Index

Welland Hydro 89%

Ontario 82%

National 81%

How can service to customers be improved?

The electric utility industry is in a state of continuous transformation. External factors - including shifts in governmental policies, a global thrust to conserve energy, advances in new technologies, and power generation are driving massive changes throughout the industry. LDCs of today and the future can also expect a much more intense level of customer involvement. UtilityPULSE research shows customers want to be heard.

Despite all the talk today centered on quality, new processes and systems, continuous improvement, and costs unless all of this is aimed at obtaining customer satisfaction, it will not be worth much over the longer term.

Qualitative questions typically do not provide statistical richness, which is associated with a quantitative question. However, they do provide words, phrases, insights into the thinking patterns and/or feelings of customers. This means qualitative questions have an interpretive richness that assists in deriving meaning from the survey. The broader range of suggestions we are getting when conducting the survey is a sign the customer base is becoming more and more segmented. Not all customers are the same.

The struggle for electric utilities is finding the right balance between cost-effective, technology-enabled approaches to customer services and person-to-person contact. Customers want their utility to focus on what matters most; offer products and services which “make a difference in their life,” “gives them peace of mind” and “delivered by trusted and credible people.”

We are interested in knowing what you think are the one or two most important things Welland Hydro could do to improve service to their customers?

One or two most important things ‘your local utility’ could do to improve service

	Welland Hydro
Better prices/lower prices	15%
Better information on outages when they occur	7%
Good/like it/satisfied/keep up the good work	6%
Better communications/be pro-active	4%
Better power reliability/less power outages	3%
Educate customers more/provide more information	3%
More/better programs/subsidies for families	3%
Use text messages to communicate	2%
Improve infrastructure	2%
Create/Improve an online / mobile app	2%
Electronic invoicing/email monthly bills/ebills	2%
None/Nothing	17%

Base: total respondents

What do customers think about electricity costs?

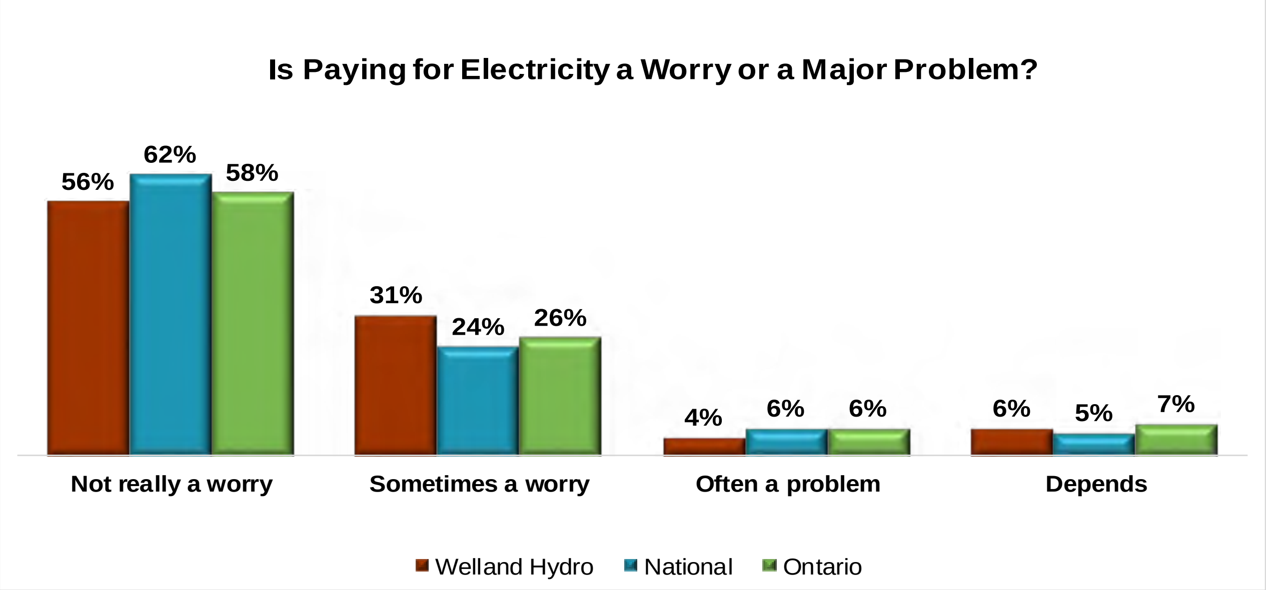
A conversation with almost any LDC customer will migrate into a conversation around cost. The concern around cost has little to do with age or income, or whether the customer uses a little or a lot of electricity – they all have a concern over costs. Unfortunately, very few customers know how much their LDC gets, of the total electricity bill, to manage the electricity network safely. A customer concern over costs is first and foremost a concern over the total bill. It doesn't help that there have been industry issues, or frequent changes to the pricing of the electricity (as a commodity). The current economic climate is only exacerbating worries. The ability to pay is highly correlated to satisfaction.

Next, I am going to read several statements people might use about paying for their electricity. Which one comes closest to your own feelings, even if none is exactly right? Paying for electricity is not really a worry. Sometimes I worry about finding the money to pay for electricity, or Paying for electricity is often a major problem?

Is paying for electricity a worry or a major problem?

	Not a worry	Sometimes	Often	Depends
Welland Hydro	56%	31%	4%	6%
National	62%	24%	6%	5%
Ontario	58%	26%	6%	7%

Base: total respondents



Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
Welland Hydro				
<$50,000	39%	48%	6%	5%
$50<$75,000	70%	22%	2%	6%
$75,000+	64%	21%	8%	6%

Base: total respondents

Is paying for electricity a worry or a major problem?				
	Not a worry	Sometimes	Often	Depends
		Ontario		
2022	58%	26%	6%	7%
2021	81%	12%	5%	2%
2020	78%	16%	3%	0%
2019	72%	19%	7%	1%
2018	68%	21%	8%	1%
		National		
2022	62%	24%	6%	5%
2021	79%	13%	4%	1%
2020	78%	15%	3%	1%
2019	74%	18%	6%	0%
2018	71%	18%	7%	0%

Base: Ontario and National Benchmarks

Cost/Value Attributes By Ability to Pay for Electricity					
	Welland Hydro	Not a worry	Sometimes	Often	Depends
Provides good value for your money	82%	87%	76%	63%	71%
Operates a cost-effective electricity system	81%	85%	78%	60%	69%
Cost of electricity is reasonable compared to other utilities	78%	84%	74%	52%	72%
Provides info/tools to help manage electricity consumption	84%	87%	82%	59%	81%

Base: total respondents with an opinion

TOU vs Tiered Pricing

55% were aware of the two different electricity rate plans.

45% were not aware of the two different electricity rate plans.

42% of those aware looked for more information to understand the differences between the two plans.

Where Looked For More Information About the Two Rate Plans

	Welland Hydro
Website tool estimator/calculator	72%
OEB calculator	19%
General web search	15%
Phone call to rep	10%
Other	11%
Don't recall / Don't know	3%

Base: those who looked for more information

Corporate Citizenship

87% agree that Welland Hydro is an active corporate citizen. Most are satisfied with the efforts made by Welland Hydro.

How Welland Hydro Could Improve Corporate Citizenship in Community

	Welland Hydro
None/Nothing/Satisfied	25%
Lower rates/change how they charge/no price gouging (low income)	11%
Donations/community donations (e.g., to the food bank, poverty)	6%
Provide information to customers about community involvement	6%
Be more visible in the community/visibility at community events	4%
Community outreach/involvement (e.g., kids/education, give back more)	3%
Just focus on providing reliable supply of electricity/keep power on	3%
Not aware of what they currently do (e.g., too new to the area)	2%
Volunteer work/employee volunteer work for non-profit organizations	2%
Community sponsorship (e.g., youth sports teams)	2%
Improve customer service (e.g., be reachable)	2%
Other	4%
Don't know	20%

Base: total respondents

Method

The findings in this report are based on a mix of telephone and online interviews conducted for UtilityPULSE Inc. by Logit Group between December 1 - December 6, 2022, with 400 respondents who pay or look after the electricity bills from a list of residential and small and medium-sized business customers supplied by Welland Hydro.

The sample of phone numbers and email addresses chosen was drawn randomly to ensure each business or residential phone number on the list had an equal chance of being included in the poll.

The sample was stratified so that 85% of the interviews were conducted with residential customers and 15% with commercial customers.

In sampling theory, in 19 cases out of 20 (95% of polls in other words), the results based on a random sample of 400 residential and commercial customers will differ by no more than ±4.90 percentage points where opinion is evenly split.

This means you can be 95% certain that the survey results do not vary by more than 4.90 percentage points in either direction from results that would have been obtained by interviewing all Welland Hydro residential and small and medium-sized commercial customers if the ratio of residential to commercial customers is 85%:15%.

The margin of error for the sub-samples is larger. To see the error margin for subgroups, use the calculator at http://www.surveysystem.com/sscalc.htm.

Interviewers reached 7,309 households and businesses via phone or email from the customer list supplied by Welland Hydro. The 400 who completed the interview represents a 5% response rate, thus highlighting the importance of also using email to reach customers to ensure a representative sample.

The findings for the UtilityPULSE National Benchmark of Electric Utility Customers are based on telephone interviews conducted with adults throughout the country who are responsible for paying electric utility bills. The ratio of 85% residential customers and 15% small and medium-sized business customers in the National study reflects the ratios used in the local community surveys. The margin of error in the National poll is ±3.10 percentage points at the 95% confidence level. The margin of error in the Ontario poll is ±3.10 percentage points at the 95% confidence level.

For the National study, and the Ontario study, the sample of phone numbers and email addresses chosen was drawn by recognized probability sampling methods to ensure each region of the country/province was represented in proportion to its population and by a method that gave all residential telephone numbers, both listed and unlisted, an equal chance of being included in the poll.

The data were weighted in each region of the country to match the regional shares of the population.

The margin of error refers only to sampling error; other non-random forms of error may be present. Even in true random samples, precision can be compromised by other factors, such as the wording of questions or the order in which questions were asked.

Random samples of any size have some degree of precision. A larger sample is not always better than a smaller sample. The important rule in sampling is not how many respondents are selected but how they are selected. A reliable sample selects poll respondents randomly or in a manner which ensures that everyone in the population being surveyed has an equal chance of being selected.

How can a sample of only several hundred truly reflect the opinions of thousands or millions of electricity customers within a few percentage points?

Measures of sample reliability are derived from the science of statistics. At the root of statistical reliability is probability, the odds of obtaining a particular outcome by chance alone. For example, the chances of having a coin come up heads in a single toss are 50%. A head is one of only two possible outcomes.

The chance of getting two heads in two coin tosses is less because two heads are only one of four possible outcomes: a head/head, head/tail, tail/head, and tail/tail.

But as the number of coin tosses increases, it becomes increasingly more likely to get outcomes that are either close to or exactly half heads and half tails because there are more ways to get such outcomes. Sample survey reliability works the same way but on a much larger scale.

As in coin tosses, the most likely sample outcome is the true percentage of whatever we are measuring across the total customer base or population surveyed. Next, most likely are outcomes very close to this true percentage. A statement of the potential margin of error or sample precision reflects this.

Some pages in the computer tables also show the standard deviation (S.D.) and the standard error of the estimate (S.E.) for the findings. The standard deviation embraces the range where 68% (or approximately two-thirds) of the respondents would fall if the distribution of answers were a normal bell-shaped curve. The spread of responses is a way of showing how much the result deviates from the "standard mean" or average. In the Welland Hydro data on corporate image, the answers were converted to a point scale with 4 meaning agree strongly, 3 meaning agree somewhat, and so on.

Beneath the S.D.. in the tables is the standard error of the estimate. The S.E. is a measure of confidence or reliability, roughly equivalent to the error margin cited for sample sizes. The S.E. measures how far off the sample's results are from the standard deviation. The smaller the S.E., the greater the reliability of the data. In other words, a low S.E. indicates the answers given by respondents in a certain group (such as residential bill payers or women) do not differ much from the probable spread of the answers "predicted" in sampling and probability theory.

In certain instances, all of the sub-datasets from the entire UtilityPULSE database for 2022 were concatenated in order to use the average of all the control samples for comparison.

UtilityPULSE, through polls and surveys, provides executives and managers with customer feedback that assists in making strategic and operational decisions. You know lots of companies that can gather data and then give a report. We believe that by specializing in the utility sector with our polls and surveys, you get a stronger analysis of data and answers to critical questions that help you formulate key strategies to assist your leaders in creating a better place to work and a better place to do business with.

UtilityPULSE is uniquely positioned to help your utility get feedback from Customers through its Annual Electric Utility Customer Satisfaction Survey or customized research designed for you. In addition, we understand what it takes to create an organization where employees are engaged and enthusiastic about customers and their work.

We're the only research company with 24 continuous years of producing an independent Ontario and National benchmark.

Anyone can collect and present data – we believe understanding the industry before doing so is crucial.

Contact us when experience, expertise, and high standards are essential for your next customer engagement activity. We promise to listen to your needs and design and delivery a customer engagement activity or survey which meets your needs.

Your personal contact is:

David Malesich

Phone: (647) 274-9420 E-mail: david@utilitypulse.com

Appendix 1-G: 2025 Cost of Service Checklist

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch1, p4	Confidential Information - Practice Direction has been followed	Practise Direction Followed
Ch1, p5	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable).	Exhibit 1 - Appendix 1-B
Ch1, p5	Certification by a senior officer that the evidence filed (including the models and appendices) is accurate, consistent and complete to the best of their knowledge	Exhibit 1 - Appendix 1-B
Ch1, p5	Certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that the distributor has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition	Exhibit 1 - Appendix 1-B
Ch2, p2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit 1 - Appendix 1-G
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Each exhibit has related Appendices in PDF, live excel attached, WHESC_2024_Current_Tariff_2024_08_23 in pdf, live excel attached
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was amended	Exhibit 1 - Appendix 1-H
3	Regulated entity shown seperately from parent company or any other affiliates	WHESC separate from affiliates and parent throughout Application
3 & 4	If applicable, if cost of service filed earlier than scheduled, justify why an early rebasing is required by demonstrating why and how distributor cannot adequately manage resources and financial needs during IRM period	Not Applicable - last filing 2017
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	Not Applicable - filed on time
4 & 5	All of the following exhibits filed: Application Overview and Administrative Documents, Rate Base and Capital (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Complete and Submitted
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Completed
5	Documents must include page numbers and be provided in text searchable and bookmarked PDF format	Completed
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Completed and Submitted
7	Materiality threshold: Explanation/justification and/or supporting evidence for material amounts pertaining to CAPEX, capital variances, rate base variances, OM&A, and DVAs; additional details below the threshold if necessary	Completed Throughout, Materiality Calculated in Exhibit 1 - Section 1.3.7
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	WHESC_2025_TOC_COS_2024_08_23 in PDF format, Each individual Exhibit has its own TOC which is appropriately bookmarked.
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business and/or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term. Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the Business Plan. Also provide Strategic Plan, if available.	Exhibit 1, Appendix 1-A
8 & 9	Brief, plain language summary of the application which includes the main requests with section references and rationale behind each request. Must include: -Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes -Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved)) -Rate base and DSP (major drivers of DSP and cost trends, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %) -OM&A (OM&A requested for test and change from last OEB-approved ($ and %), drivers and cost trends) -Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary of deviations from OEB methodology) -Cost allocation and rate design (proposed new customer classes and/or customer definition changes, new proposed charges, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans) -DVAs (total disposition ($) including split between customer classes and between RPP and non-RPP (if applicable), disposition period(s), new DVAs and requested discontinuation of DVAs) -Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	Exhibit 1, Section 1.2
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit 1, Section 1.3.2
9	Identification of legal (or other) representation	Exhibit 1, Section 1.3.3
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	Exhibit 1, Section 1.3.4
9	Statement identifying where notice should be published and why	Exhibit 1, Section 1.3.5
9	Form of hearing requested and why	Exhibit 1, Section 1.3.8

2025 Cost of Service Checklist

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
9	Requested effective date	Exhibit 1, Section 1.3.9
10	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1, Section 1.3.10
10	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	Exhibit 1, Section 1.3.11
10	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit 1, Section 1.3.12
10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the distributor; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit 1, Section 1.3.13
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented - Appendix 2-A provided, but not required to be used by LDC	Exhibit 1, Section 1.3.14
Distribution System Overview		
10	Description of Service Area - general description and map showing where distributor operates and communities served	Exhibit 1, Section 1.4
Customer Engagement		
11	Provide information regarding its customer engagement activities, activities that occur on an on-going basis, and specific activities pertaining to application. **May** use Appendix 2-AC to assist in listing customer engagement activities	Exhibit 1, Section 1.5, Appendix 2-AC not included
11	Ongoing Customer Engagement - Describe methods used to communicate and engage with each customer class regularly, summarize pertinent feedback received through regular customer communications, and explain how feedback informs operations and rate application, where applicable	Exhibit 1, Section 1.5.1
11 & 12	Application-Specific Customer Engagement - Explain customer engagement process specific to application (tailor customer engagement activities to distributor's circumstances and the proposals in application). Demonstrate how customer needs and priorities were factored into the decision-making process	Exhibit 1, Section 1.5.2
12	Customer engagement with customers who would be affected by proposals related to new rate classes, changes in to existing rate classes and change in charges such as RSCs, Specific Service Charges, standby rates, and unmetered-load customers	Exhibit 1, Section 1.5
12	All responses to matters raised in letters of comment filed on public record	Not at the time of filing, will include as Letters of Comment Received
Performance Measurement		
12	Link to most recent scorecard	Exhibit 1, Appendix 1-C
12	Identification of performance improvement targets	Included in Business Plan - Attachment 1-A DSP - Section 5.2.3
12	PEG Model for the test year showing efficiency assessment, discussion on how the results obtained from the PEG model has informed the distributor's business plan and application	Exhibit 1, Section 1.6.1.2
12 & 13	Distributors **may** wish to provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per PEG model	Not Included
13	Activity and Performance-based Benchmarking (APB) results - at least provide the following unit cost variance analysis: - Year-over-year Historical Actuals (for most recent APB results) - Forecast Bridge Year vs Historical Actuals, to extent possible - Test Year vs Historical Actuals, to extent possible	Exhibit 1, Section 1.6.2
13	Explain variances in cost performance, whether changes in unit costs are within distributor's control, and discuss relevant actions planned or underway. Discuss econometric results to extent possible	Exhibit 1, Section 1.6.2
Facilitating Innovation		
13 & 14	Distributors are encouraged to include a description of the ways their approach to innovation has shaped the application. Could include explanations of approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision of distribution services; and of enabling characteristics or constraints in their ability to undertake innovative solutions. Explain how innovative alternatives have been considered in place of traditional investments	Exhibit 1, Section 1.7
14	Explain how innovative alternatives have been considered in place of traditional investments. Include information about the costs, expected benefits and associated risks of innovative alternatives	Exhibit 1, Section 1.7
Financial Information		
14	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	Exhibit 1, Appendix 1-D and Appendix 1-E
15	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable. If an Annual Information Form is filed publicly, a link should be provided	Not Applicable
15	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	Not Applicable
15	Any change in tax status	Exhibit 1, Section 1.8.5
15	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1, Section 1.8.6
15	Accounting Standards used for financial statements and when adopted	Exhibit 1, Section 1.8.8
15	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	Exhibit 1, Section 1.8.9
Distributor Consolidation		

2025 Cost of Service Checklist

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EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
15	Information filed on the extent to which the distributor has investigated opportunities for consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	Exhibit 1, Section 1.9
15	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	Not Applicable
A distributor filing an application to rebase following a consolidation must:		
15	Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	Not Applicable
16	Specify whether and which commitments made to shareholders are to be funded through rates	Not Applicable
16	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	Not Applicable
16	Detail of efficacy of any rate plan confirmed as part of MAADs	Not Applicable
16	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	Not Applicable
Impacts of COVID-19 Pandemic		
16	Distributors generally expected to reflect the impacts of the COVID-19 pandemic in their applications, including applicable forecast information. This includes, but is not limited to, the distributor's load forecast, capital forecast, and OM&A forecast in the applicable sections of the application	Exhibit 1, Section 1.10
EXHIBIT 2 - RATE BASE AND CAPITAL		
Rate Base		
16	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. If not, specify whether variance explanations are on CAPEX or in-service additions basis	Exhibit 2 - Section 2.1.1
16	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	Exhibit 2 - Table 2-1
16	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit 2 - Table 2-3
Fixed Asset Continuity Schedule		
17	Completed Appendix 2-BA for each year - in Excel format	Exhibit 2 - Appendix 2-C
17	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	Exhibit 2 - Section 2.2.2
17	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit 2 - Appendix 2-C
17 & 18	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and if disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	Exhibit 2 - Section 2.1.1, Table 2-2, Table 2-3, Table 2-4
18	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Not Applicable
18	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit 2 - Section 2.4.1
18	All asset disposals clearly identified in Chapter 2 Appendices for all historical, bridge and test years	Exhibit 2 - Appendix 2-C
Depreciation, Amortization and Depletion		
18	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Exhibit 2 - Section 2.4.1
18	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Exhibit 2 - Appendix 2-C (OEB Appendix 2-BA) and Appendix 2-D (OEB Appendix 2-C). The depreciation expense amounts shown in these two documents match.
18	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	Exhibit 2 - Section 2.4.2
19	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit 2 - Section 2.4.1
19	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit 2 - Section 2.4.1
19	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Exhibit 2 - Section 2.4.1
19	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	Exhibit 2 - Section 2.4.1, OEB Appendix 2-BB has been updated to reflect changes since the last COS.
Allowance for Working Capital		
19 & 20	Working Capital - 7.5% allowance or Lead/Lag Study. If previously ordered by OEB as part of last rate application to file Lead/Lag Study, must comply.	Exhibit 2 - Section 2.5

2025 Cost of Service Checklist

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EB-2024-0058

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20	If Lead/Lag Study conducted - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	Not applicable
20	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-Z - Commodity Expense.	Exhibit 2 - Section 2.5.1.2
20	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Exhibit 2 - Section 2.5.1.2
Distribution System Plan		
20	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit 2 - Appendix 2-E
Policy Options for the Funding of Capital		
21	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence	Exhibit 2 - Section 2.7 (Not Applicable)
21	Identification that distributor is proposing ACM treatment for these future projects and provide the preliminary cost information, and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	Not Applicable
21	Complete Capital Module Applicable to ACM and ICM	Not Applicable
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
22	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	Exhibit 2 - Section 2.8 (Not Applicable)
22	Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	Not Applicable
22	True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g., half-year rule).	Not Applicable
23	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Not Applicable
Capitalization		
24	Capitalization Policy: provide policy including changes since last rebasing application. Confirm if no changes made to capitalization policy since last rebasing application.	Exhibit 2 - Section 2.9.1
24	Overhead Costs: complete Appendix 2-D	Exhibit 2 - Section 2.9.2
24	Burden Rates: identification of burden rates; if burden rates were changed since last rebasing, identification of the burden rates prior to the change	Exhibit 2 - Section 2.9.3
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
24	See Appendix A	Exhibit 2 - Section 2.10
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	Consistent with Chapter 5 Sections
Investment Categories		
Ch5, pp 2, 3 & 4	Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	DSP - Section 5.2.1.2
Distribution System Plan		
Ch5, p4	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	Not Applicable
Ch5, p5	DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application..	DSP - Section 5.2.1
Distribution System Plan Overview		
Ch5, p5	High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP, which will be used as a baseline comparison in the performance measurement section below.	DSP - Section 5.2.1.2, Section 5.2.1.3. Section 5.2.1.4
Coordinated Planning with Third Parties		
Ch5, p5	The distributor must demonstrate that it has coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultation and relevant material supporting the effects the consultation had on the DSP.	DSP - Section 5.2.2
Ch5, p5	Overview of consultation should include: purpose, outcome, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	DSP - Section 5.2.2
Ch5, p5	A distributor should file the most recent regional plan. In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter.	DSP - Section 5.2.2.5, Section 5.2.2.8
Ch5, p5 & 6	Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	DSP - Section 5.2.2.8
Ch5, p6 & OEB Letter, Jan. 11, 2022	Telecommunications Entities: See January 11, 2022 letter for further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan: -number of consultations conducted and a summary of the manner in which the distributor determined with whom to consult; a summary of the results of the consultation; and a statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.	DSP - Section 5.2.2.9

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch5, p6	REG: -confirmation if there are REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	DSP - Section 5.2.2.10
Performance Measurement for Continuous Improvement		
Ch5, p6 & 7	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in Section 5.2.1.	DSP - Section 5.2.3.1.1
Ch5, p7	Service Quality and Reliability: -5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues -for reliability, any declining 5 year SAIDI/SAIFI trends explained -if reliability targets established in last DSP, any under-performance explained	DSP - Section 5.2.3.2
Ch5, p7	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	DSP - Section 5.2.3 1, Table 5.2-8
Ch5, p7	Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. Summary must include historical period data on: -all interruptions -all interruptions excluding loss of supply -all interruptions excluding major events and loss of supply for: SAIFI, SAIDI	DSP - Sectioin 5.2.3.2.5
Ch5, p7	Summary of major events that occurred since last cost of service	DSP - Sectioin 5.2.3.2.5 (No MEDs)
Ch5, p7 & 8	For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	DSP - Section 5.2.3.2.5
Ch5, p8	Distributor Specific Reliability Targets: -if establishing performance expectations based on something other than historical performance, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributors plan to deliver -summary of any feedback from customers regarding reliability on distributors' system -distributors that use SAIDI and SAIFI performance benchmarks that are different than the historical average - evidence provided to support reasonableness of benchmarks	DSP - Section 5.2.3.3
Planning Process		
Ch5, p8	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	DSP - Section 5.3.1.1
Ch5, p8	Summary of important changes in distributor's AM process since last DSP	DSP - Section 5.3.1.2
Ch5, p9	Process: -provide processes used to identify, select, prioritize (including reprioritization over 5 year term), optimize, and pace execution of investments -demonstration that distributor has considered correlation between plan and customer's feedback and needs -demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures -demonstrate how it does grid optimization using an approach that considers the distributor's whole system -consideration, where applicable, of assessing the use of non-wires alternatives, distributed energy resources, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, other innovative technologies, and consideration of dx funded CDM activities	DSP - Section 5.3.1.3
Ch5, p9	Data -identification, description and summary of data used in processes above to identify, select, prioritize, optimize and pace investments over DSP	DSP - Section 5.3.1.4
Overview of Assets Managed		
Ch5, p10	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, utilization, condition, failures/performance, asset risks, demographics) by major asset type that may help explain the specific need for the capital expenditure and demonstration of consideration of economic alternatives	DSP - Section 5.3.2.1, Section 5.3.2.2
Ch5, p10	Statement as to whether distributor has had any transmission or high voltage assets 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 current application	DSP - Section 5.3.2.3
Ch5, p10	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	DSP - Section 5.3.2.4
Asset Lifestyle Optimization Policies and Practices		
Ch5, p11	Demonstration that distributor has carried out cost-effective system O&M activities to sustain as asset to the end of its service life (and can include references to the Distribution System Code)	DSP - Section 5.3.3.1, Section 5.3.3.2
Ch5, p11	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	DSP - Section 5.3.3.3
Ch5, p11	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	DSP - Section 5.3.3.3.3
Ch5, p11	Demonstration that the distributor has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints	DSP - Section 5.3.3.1
Ch5, p11	Summary of important changes to the distributor's asset life optimization policies, processes, and tools since last DSP	DSP - Section 5.3.3.4
System Capability Assessment for REG and DER		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: **August 23, 2024**

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch5, p11	Provide list of restricted feeders by name, the feeder designation, the reason for the restriction, number of connected customers, and explain if there are plans to improve the distribution system's ability to connect distributed energy resources	DSP - Section 5.3.4, Section 5.2.2.10
Ch5, p11	If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A	WHESC had histroical REG investment prior to the 2017 COS. (Refer to Exhibit 2, Section 2.10). WHESC is not forecasting any REG investments (Refer to DSP - Appendix 5-F).
CDM Activities to Address System Needs		
Ch5, p12	Description of how distributor has taken CDM into consideration in its planning process	DSP - Section 5.3.5
Ch5, p12	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.	Not Applicable
Ch5, p12	Explanation of proposed activity in the context of the DSP, including providing details on the system need that is being addressed, infrastructure investments that are being avoided or deferred as a result of CDM activity, and the prioritization of proposed CDM activity relative to other system investments in the DSP	Not Applicable
Ch5, p12	Description of the approach to assessing the benefits and costs of CDM activity	Not Applicable
Capital Expenditure Summary		
Ch5, p13	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	DSP - Section 5.4
Ch5, p13	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	DSP - Section 5.4 - Table 5.4-1, Table 5.4-2
Ch5, p13	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	DSP - Section 5.4.1.2 - Table 5.4-10 through Table 5.4-14
Ch5, p13	Completed Appendices 2-AA and 2-AB	Exhibit 2 - Appendix 2-A, Appendix 2-B
Ch5, p13	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment or category, including actuals v. OEB-approved/planned amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances between planned and actual volume of work completed and explanation of variances in a given year that are much higher or lower than the historical trend	DSP - Section 5.4.1.1 - Table 5.4-3 through Table 5.4-9
Ch5, p13	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	DSP - Section 5.4.1.2.5
Ch5, p14	Analysis of capital expenditures in DSP forecast period v. historical	DSP - Section 5.4.1.3
Ch5, p14	Summary of any important modifications to typical capital programs since the last DSP	DSP - Section 5.4.1.4
Ch5, p14	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	DSP - Section 5.4.1.5
Ch5, p14	Statement that there are no expenditures for non-distribution activities in the applicant's budget	DSP - Section 5.4.1.6
Justifying Capital Expenditures		
Ch5, p14	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	DSP - Section 5.4.2
Material Investments		
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		
Ch5, p15	General information on the project/program - Need, scope, volume of work expected to be completed, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, cost/benefit of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the filing requirements	DSP - Appendix 5-A (Materiality Narratives) - "General Information on the Program/Project"
Ch5, p15	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including CDM activities if applicable), benefits for customers, impact on distributor costs -If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines	DSP - Appendix 5-A (Materiality Narratives) - "General Information on the Program/Project" & "Evaluation Criteria and Information Requirements"
Ch5, p16	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, CDM, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate	DSP Appendix 5-A (Materiality Narratives) - "Evaluation Criteria and Information Requirements"
Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	DSP - Appendix 5-F
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	DSP - Appendix 5-F, DSP - Appendix 5-G
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		

2025 Cost of Service Checklist
LDC: Welland Hydro Electric System Corp.
EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Load Forecasts		
24	Weather normal load forecast provided	Exhibit 3 - Section 3.1, Table 3-17
24	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Exhibit 3 - Section 3.1
24	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	Exhibit 3 - Section 3.1.1.1
25	Explanation of weather normalization methodology	Exhibit 3 - Section 3.1.1.1, Section 3.1.1.2
25	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Exhibit 3 - Section 3.1 - Appendix 3-B
25 & 26	Multivariate Regression Model -rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested -statistics should include, but not limited to, the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error and Durbin-Watson statistic), including explanation for any resulting non-intuitive relationships -explanation of weather normalization methodology (including if monthly HDD and/or CDD are used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence -definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees -sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling -any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided -explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total for purchased power -description of how CDM impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast -data and regression model and statistics used in customer and load forecast in Excel format	Exhibit 3 - Section 3.1.1 (Multivariate Regression Model); Exhibit 3 - Section 3.1.3 (CDM Impacts)
26	NAC Model -rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast -data supporting calculation of NAC values for each rate class -description of how CDM impacts and other exogenous factors have been accounted for in historical period and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into test year forecast -discussion of weather normalization assumptions used	Exhibit 3 - Section 3.1.2
Incorporating CDM Impacts in the Load Forecast for Distributors		
27	Distributor may request approval for the use of the LRAMVA for a new CDM activity (a distribution-rate funded CDM activity or the Local Initiatives Program (LIP)), which would require establishing an LRAMVA threshold. If a distributor does request to establish an LRAMVA threshold, documentation of the CDM savings to be used as the basis for the 2023 LRAMVA threshold, and description of how these savings are aligned with the 2023 load forecast	Exhibit 3 - Section 3.1.3
28	If a distributor proposes a different savings values for a CDM activity in the load forecast and LRAMVA threshold, description of rationale for these differences (e.g., timing of CDM activity, line loss factor, net-to-gross conversion factor)	Not Applicable
Accuracy of Load Forecast and Variance Analyses		
28	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Exhibit 3 - Section 3.2
28	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	Exhibit 3 - Section 3.2 and Sections 3.2.1 to 3.2.9
28	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	Exhibit 3 - Section 3.1.1.4; Section 3.2; and Sections 3.2.1 to 3.2.9
29	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	WHESC_2025_Load Forecast Model_2024_08_23
EXHIBIT 4 - OPERATING EXPENSES		
Overview		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: **August 23, 2024**

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
29	Brief explanation (quantitative and qualitative) of test year OM&A levels, how the distributor develops and receives approval of their OM&A budget, cost drivers and significant changes relative to historical and bridge years, trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years, inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal), business environment changes	Exhibit 4 - Section 4.1
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
29	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit 4 - Section 4.2.1
29	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit 4 - Section 4.2.2
29	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Exhibit 4 - Section 4.3
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Exhibit 4 - Section 4.2.3
29 & 30	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	Not Applicable
30	Only distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed instead of 2-JC	Exhibit 4 - Section 4.3 (2-JC Selected)
30	For all distributors, the table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Exhibit 4 - Section 4.3
30	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Exhibit 4 - Section 4.2.1, Section 4.2.2
30	Identification of change in OM&A in test year in relation to change in capitalized overhead	Exhibit 4 - Section 4.2.4
OM&A Variance Analysis		
30	Re: 2-JC or 2-JD - variance analysis between: -test year vs last OEB approved -historical OEB-approved vs historical actuals (for the most recent historical OEB-approved year) -test year vs bridge year	Exhibit 4 - Section 4.3
30	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	Not Applicable
30	For all distributors, the variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	Exhibit 4 - Section 4.3
Workforce Planning and Employee Compensation		
31	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Exhibit 4 - Section 4.3.1.1
31	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Not Applicable
31	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit 4 - Section 4.3.1
31	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - Variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	Exhibit 4 - Section 4.3.1
31	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit 4 - Section 4.3.1.6
31	Most recent actuarial report; tax section of evidence agrees with this analysis	Exhibit 4 - Appendix 4-F
31	For virtual distributors - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated distributor. Provide the status of pension funding and all assumptions used in the analysis	Not Applicable
32	Indication if pension and OPEBs to be recovered using cash or accrual method. If cash method, sufficient supporting rationale and evidence for adopting cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	Exhibit 4 - Section 4.3.1.6
Shared Services and Corporate Cost Allocation		
32	Identification of all shared services among affiliates; identification of the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	Exhibit 4 - Section 4.3.2
32	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit 4 - Section 4.3.2
32	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	Exhibit 4 - Section 4.3.2
32	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	Exhibit 4 - Section 4.3.2 Exhibit 6 - Section 6.3.3
32 & 33	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit 4 - Section 4.3.2.3
33	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit 4 - Section 4.3.2.3
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit 4 - Appendix 4-H
33	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	Not Applicable
33	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test year. If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	Exhibit 4 - Section 4.3.4
33 & 34	Regulatory costs - breakdown of actual and anticipated regulatory costs including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), information supporting incremental level of costs for preparation and review of current application, proposed recovery (i.e. amortized?), explanation if different than 5 years, completed Appendix 2-M	Exhibit 4 - Section 4.3.5
LEAP, Charitable and Political Donations		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		**Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)**
34	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	Exhibit 4 - Section 4.3.6
34	For any charitable contributions claimed for recovery, detailed information provided	Exhibit 4 - Section 4.3.7
34	Confirmation that no political contributions have been included for recovery	Exhibit 4 - Section 4.3.7
Conservation and Demand Management		
35	Statement confirming that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement	Exhibit 4 - Section 4.4
35	Distributor should generally not include any forecast costs associated with partnership in the IESO's LIP within its revenue requirement; distributor can seek to recover partnership costs at a future date through the LIP deferral account. If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	Not Applicable
Funding Options for Future Conservation and Demand Management Activities		
35	If CDM activities included in COS where CDM activities expected to come into service during Price Cap IR term, identification of if costs of such CDM activities included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future CDM activities	Not Applicable
35	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	Not Applicable
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
36	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision. Alternatively - distributor specific cost of capital with supporting evidence and justification	Exhibit 5 - Section 5.1.1
36	Completed Appendix 2-OA for last OEB approved and test years	Exhibit 5 - Section 5.1.2; Table 5-2 and Table 5-3
36	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	Exhibit 5 - Section 5.1.3; Tables 5-4 to 5-12
36	Explanation for any material changes in capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	Exhibit 5 - Section 5.1.4
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
37	Calculation of cost for each capital component	Exhibit 5 - Section 5.2
37	Profit or loss on redemption of debt, if applicable	Exhibit 5 - Section 5.2.3
37	Copies of current promissory notes or other debt arrangements with affiliates	Exhibit 5 - Section 5.2.4
37	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report or applicant's proposed approach	Exhibit 5 - Section 5.2.5
37	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party?)	Exhibit 5 - Section 5.2.5
37	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Exhibit 5 - Section 5.2.5
37	Historical return on equity achieved	Exhibit 5 - Section 5.2.6
Not-for-Profit Corporations		
37	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	Not Applicable
38	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	Not Applicable
38	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	Not Applicable
38	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	Not Applicable
38	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	Not Applicable
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
38	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each) excluding energy costs and revenues and unregulated costs and revenues: -determination of net income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	Exhibit 6 - Section 6.0
38 & 39	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects) and for which disposition is not being sought in the application.	Exhibit 6 - Section 6.0
39	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit 6 - Section 6.0.7
39	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	Exhibit 6 - Section 6.0.8
Revenue Requirement Work Form		
39	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Exhibit 6 - Appendix 6-A; WHESC_2025_Revenue_Requirement_Workform_2024_08_23
39	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	Confirmed that the RRWF reflects WHESC's proposed rates accurately. No rate generator model has been filed.
40	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Exhibit 6 - Section 6.1
Income Tax or PILs		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: **August 23, 2024**

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
40	Must provide detailed calculations of income tax or PILS. Must include a completed Excel version of the PILs model available on the OEB's website, including derivation of adjustments for historical, bridge and test years. Regulatory assets and liabilities must excluded from PILs calculations when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.	Exhibit 6 - Section 6.2; Appendix 6-B WHESC_2025_Test_Year_Income Tax_PILs_2024_08_23 WHESC_2025_Revenue_Requirement_Workform_2024_08_23
40	Supporting schedules and calculations identifying reconciling items	Exhibit 6 - Section 6.2; Appendix 6-B WHESC_2025_Test_Year_Income Tax_PILs_2024_08_23
40	Most recent federal and provincial tax returns	Exhibit 6 - Appendix 6-C
40	Financial Statements included with tax returns if different from those filed with application	Not Applicable - Financial Statements included with Tax Returns consistent with Financial Statements filed with the application
40	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	Exhibit 6 - Section 6.2; Appendix 6-B WHESC_2025_Test_Year_Income Tax_PILs_2024_08_23
41	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit 6 - Section 6.2; Appendix 6-B WHESC_2025_Test_Year_Income Tax_PILs_2024_08_23
41	Completion of the integrity checks in the PILs Model	Exhibit 6 - Section 6.2.1.6
41	Accelerated CCA - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, method used in calculating the revenue requirement impact recorded in Account 1592, detailed calculations by year for the full revenue requirement impact recorded in Account 1592	Exhibit 6 - Section 6.2.1.7
41 & 42	May propose a mechanism to smooth the tax impacts over the five-year IRM term.	Not applicable
Other Taxes		
42	Account 6105 is not an OM&A account and should be excluded from all OM&A totals. Applicant should provide an explanation of how these tax amounts are derived.	Exhibit 6 - Section 6.2.2
Non-recoverable and Disallowed Expenses		
42	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit 6 - Section 6.2.3
Other Revenue		Exhibit 6 - Section 6.3
42	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Exhibit 6 - Section 6.3.2
42 & 43	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	Exhibit 6 - Section 6.3; Section 6.3.1; Section 6.3.2; Section 6.3.3
43	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historical years, the bridge year and the test year. Any differences must be reconciled	Exhibit 6 - Section 6.3.3
43	Revenue related to microFIT recorded as revenue offset in Account 4235 and not included as part of base revenue requirement	Exhibit 6 - Section 6.3.4
43	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	Exhibit 6 - Section 6.3.3
43	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	Exhibit 6 - Section 6.3.3
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
44	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	Exhibit 7 - Section 7.1
44	Description of weighting factors, rationale for use of default values (if applicable)	Exhibit 7 - Section 7.1
44	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	Not applicable
45	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.	WHESC_2025_Cost_Allocation_Model_2024_08_23
Load Profiles and Demand Allocators		
45	Update all classes' load profiles and update demand allocators, if class load profiles are unavailable, provide an explanation and commit to putting plans in place to remedy this for next time a cost allocation model is filed	Exhibit 7 - Section 7.1.1
45	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Exhibit 7 - Section 7.1.1
45	If multivariate regression used, the following provided: -statistics and statistical tests related to regression equation(s) coefficients and intercept -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the soruce of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	Not Applicable - Exhibit 7 - Section 7.1.1
46	Data and regression model and statistics used in the weather normalization of load profiles provided in Excel format (includes showing the derivation of any constructed variables)	Not Applicable - Exhibit 7 - Section 7.1.1
46	Demand Allocators: spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	Exhibit 7, Section 7.1.1, WHESC_Load_Forecast_Model_2024_08_23

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
46	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	Exhibit 7, Section 7.1.1, Using Weather Actual Load Profiles Three years historical data was available and used.
46 & 47	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q - Cost of Serving Embedded Distributors	Not applicable
47	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	Exhibit 7 - Section 7.1.2.4
48	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	Exhibit 7 - Section 7.1.2.5
48	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	Exhibit 7 - Section 7.1.3
48	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	Exhibit 7 - Section 7.1.4
Class Revenue Requirements		
49	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor.	Exhibit 7 - Section 7.2
Revenue to Cost Ratios		
49 & 50	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant.	Exhibit 7 - Section 7.3
50	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	Not applicable
50	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	Not applicable
EXHIBIT 8 - RATE DESIGN		
50	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	Exhibit 8 - Setion 8.1.1.4
Fixed Variable Proportion		
50 & 51	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Exhibit 8 - Section 8.1
RTSRs		
51	Completed RTSR Model in Excel	Exhibit 8 - Section 8.2; WHESC_2025_RTSR_Workform_2024_08_23
51	RTSR information consistent with working capital allowance calculation; explanation for any differences	Exhibit 8 - Section 8.2
Retail Service Charges		
51	Distributors should note that the current retail service rates and charges were established on a generic basis and should refer to the most recent rate order for the current approved rates.	Exhibit 8 - Section 8.3
Regulatory Charges		
52	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	Exhibit 8 - Section 8.4
Specific Service Charges		
52	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	Exhibit 8 - Section 8.5
52	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	Exhibit 8 - Section 8.5
52	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	Not applicable
53	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	Exhibit 8 - Section 8.4
53	Revenue from SSCs corresponds with Operating Revenue evidence	Exhibit 8 - Section 8.5
Wireline Pole Attachment Charge		
53	Under the new regulation (Part VI.1: O. Reg. 842/21, (Electricity Infrastructure (Part VI.1 of the Act)), OEB is to establish a generic, province-wide pole attachement charge for 2022. The Regulation further requires the OEB to set the charge for 2023 and subsequent years by adjusting the prior year's charge for inflation. The Regulation provides that the annual charge will be established by order without a hearing.	Exhibit 8 - Section 8.5
Low Voltage Service Rates		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
If the distributor is fully or partially embedded, information on the following must be provided:		
54	Forecast LV Cost	Exhibit 8 - Section 8.6
54	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	Exhibit 8 - Section 8.6
54	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Exhibit 8 - Section 8.6
54	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	Exhibit 8 - Section 8.6
54	Proposed LV rates by customer class	Exhibit 8 - Section 8.6
Smart Meter Entity Charge		
55	Current OEB-approved SMC charged until the OEB approved any updated SMC	Exhibit 8 - Section 8.7
Loss Factors		
55	Proposed SFLF and Total Loss Factor for test year	Exhibit 8 - Section 8.8.2
55	Statement as to whether LDC is embedded including whether fully or partially	Exhibit 8 - Section 8.8.1
55	Study of losses if required by previous decision	Not applicable
55	3-5 years of historical loss factor data - Completed Appendix 2-R	Exhibit 8 - Section 8.8.2
55	If proposed distribution loss factor >5% or is showing an increasing trend, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	Exhibit 8 - Section 8.8.3
55	Explanation of SFLF if not standard	Not applicable
55	Reconciliation between the application and RRR filing	Exhibit 8 - Section 8.8.4
Tariff of Rates and Charges		
55	Current and proposed Tariff of Rates and Charges - **must be filed in Excel format and PDF format** Explanation and support of each change in the appropriate section of the application	Exhibit 8 - Appendix 8-B and Appendix 8-C and live excel models
55	Completed Bill Impacts Model	Exhibit 8 - Section 8.11 - Appendix 8-D
56	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	Not applicable
56	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Exhibit 8 - Appendix 8-C and live excel models
Revenue Reconciliation		
56	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Exhibit 8 - Section 8.10
56	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	Exhibit 8 - Section 8.10
Bill Impact Information		
56	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Exhibit 8 - Section 8.9 - Filed in live excel WHESC_2025_Tariff_Schedule_and_Bill_Impact_Model_2024_08_23
56	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Exhibit 8 - Section 8.11; Appendix 8-D
57	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	Exhibit 8 - Section 8.11; Appendix 8-D
57	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	Not applicable
Rate Mitigation		
57	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	Exhibit 8 - Section 8.12
Rate Harmonization Mitigation Issues		
58	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	Not applicable
58	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	Not applicable
58	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussionion of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	Not applicable
58	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	Not applicable
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
58	Summary table showing all active DVAs not disposed of yet, showing principal and interest/carrying charges, total balance for each account, whether account being proposed for disposition and whether the account is proposed to be continued or discontinued	Exhibit 9 - Section 9.1; Table 9-5 and Table 9-9
58	In a separate section under the summary table: - For any account identified, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified, provide an explanation as to why it is being discontinued	Exhibit 9 - Section 9.1; Table 9-5 and Table 9-9
58	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	Exhibit 9 - Section 9.1.8
58	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all active DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Exhibit 9 - Appendix 9-A; Also filed in live Excel format (WHESC_2025_DVA_Continuity_Schedule_2024_08_23)

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
59	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the DVA continuity schedule	Exhibit 9 - Section 9.1 - Table 9-4; Appendix A of DVA Schedule completed and included in Exhibit 9 - Appendix 9-A and live Excel format (WHESC_2025_DVA_Continuity_Schedule_2024_08_23)
59	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts"	Exhibit 9 - Section 9
59	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used for future periods	Exhibit 9 - Section 9
Disposition of Deferral and Variance Accounts		
59	Refer to DVA Continuity Schedule Instructions for instructions on completing the DVA Continuity Schedule, annual updates and discussions on default treatments and expectations for DVAs	Exhibit 9 - Section 9
59	Provide confirmation that a distributor is allocating DVAs using an approved allocator. If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	Exhibit 9 - Section 9
60	Propose rate riders that dispose of the balances. If the distributor is proposing an alternative recovery period other than one year, explanation provided	Exhibit 9 - Section 9; Section 9.1, Tables 9-7, 9-8, 9-13 and 9-14; Section 9.1.1.2, Table 9-15; Section 9.1.2, Table 9-16
60	Provide support (e.g., explanations, calculations) on how each material Group 2 balance is determined. For utility-specific Group 2 accounts that are not material, provide a brief explanation of the account balance and the relevant accounting order	Exhibit 9 - Section 9.1 - Group 2 Accounts; Section 9.1.4 Retailer Service Related Charges; Section 9.1.5 Account 1592 Sub-account CCA Changes; Section 9.1.7 Account 1508 Sub-account Pole Attachment Revenue; Section 9.1.8 Distributor Specific Account
Disposition of Accounts 1588 and 1589		
60	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	Exhibit 9 - Section 9.1.1
60	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	Exhibit 9 - Section 9.1.1
60	If requesting final disposition of balances for the first time following implementation of the accounting guidance, confirmation that accounting guidance has been implemented fully effective January 1, 2019	Not Applicable - Balances previously approved on a final basis
60 & 61	In order to request for final disposition of historical balances as part of the current application, confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Discussion on the results of the review, any systemic issues noted, and whether any material adjustments to those balances have been recorded. Summary and description of each adjustment made to the historical balances provided	Exhibit 9 - Section 9.1.1.1 and Section 9.1.1.2
61	GA Analysis Workform (in live Excel format) for each year that has not previously been approved by the OEB for disposition. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589	Exhibit 9 - Section 9.1.1.2; Filed in live Excel WHESC_2025_GA_Analysis_Workform_2024_08_23 ("GA 2023" tab)
61	As described in Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences (e.g. true-ups between estimated and actual costs and/or revenues). Any remaining unexplained discrepancy between the actual and expected balance that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Exhibit 9 - Section 9.1.1.2; Filed in live Excel WHESC_2025_GA_Analysis_Workform_2024_08_23 ("GA 2023" tab)
61	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	Exhibit 9 - Section 9.1.1.2; Filed in live Excel WHESC_2025_GA_Analysis_Workform_2024_08_23 ("Account 1588" tab)
Disposition of Account 1580, Sub-account CBR Class B Variance		
61	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance - Refer to DVA Continuity Schedule Instructions for further details on the treatment of CBR related sub-accounts	Exhibit 9 - Section 9.1.2
Disposition of Account 1595		
62	Distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	Exhibit 9 - Section 9.1.3
62	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	Exhibit 9 - Section 9.1.3
Disposition of Retail Service Charges Related Accounts		
62 & 63	If there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services - state whether Article 490 of APH has been followed; explanation if not followed	Exhibit 9 - Section 9.1.4
63	If the balances in Account 1518, Account 1548, or Account 1508 Sub-account Retail Service Charges Incremental Revenue are material, the distributor must identify drivers for the balance(s) and provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances	Exhibit 9 - Section 9.1.4
63	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account, as well as in Accounts 1518 and 1548, would be disposed to ratepayers in a future rate application, and the account subsequently closed. Distributors that have not yet done so in a COS application may forecast balances up to the end of the incentive rate-setting period and the OEB may consider disposing of the forecast amounts	Exhibit 9 - Section 9.1.4
Disposition of Account 1592, Sub-account CCA Changes		
63 & 64	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: underpreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences. other applicable information	Exhibit 9 - Section 9.1.5
64	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	Not applicable
64	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	Exhibit 9 - Section 9.1.5
64	If a distributor does not have a balance in this sub-account, the distributor must explain why	Not applicable
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		**Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)**
64 & 65	If requesting disposition of any amounts related to the COVID-19 Account, the following, at a minimum is to be provided: -Discussion regarding the interactions between the COVID-19 Account and other existing generic or utility-specific accounts, including a determination that there is no double-counting between multiple ratemaking mechanisms -Calculation showing that the distributor passes the ROE-based means tests, including limitations on recoveries when various ROE thresholds are reached, and that the appropriate recovery rates for each sub-account have been applied -Supporting calculations for the annual amounts recorded in each of the sub-accounts, including the methodology used to measure incremental costs and savings, as applicable - Discussion of causation, materiality, prudence of any amounts recorded in the sub-accounts, including all identified savings and cost reductions -Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective date of the new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach) -Statement confirming proposed discontinuation of the COVID-19 Account, effective the same date as the new rates. If this is not the case, supporting rationale provided	Exhibit 9 - Section 9.1.6
Disposition of Account 1508, Sub-account Pole Attachment Revenue Variance		
65	A table showing the calculation of the account balance, the annual balance broken down customer type, if applicable and: -the number of poles used in the calculation -the pole attachment charge incorporated in rates -the updated charge May also foecast the balance to the effective date of its new rates	Exhibit 9 - Section 9.1.7
Disposition of Distributor-Specific Accounts		
66	For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived and relevant accounting order should be provided. For distributor-specific accounts requested for disposition that are not material, provide a brief explanation for the account balance and the relevant accounting order.	Exhibit 9 - Section 9.1.8
Establishment of New Deferral and Variance Accounts		
66 & 67	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order with description of the mechanics of the account, provide examples of general journal entries and the proposed account duration	Exhibit 9 - Section 9.2
Lost Revenue Adjustment Mechanism Variance Account		
67	In preparing claims related to disposition of outstanding LRAMVA balances, distributors may seek to claim savings from Conservation First Framework (CFF) programs, and from programs they delivered through the Local Program Fund that was part of the Interim Framework. Distributors should provide sufficient supporting documentation on project savings to support their claim	Exhibit 9 - Section 9.3
Disposition of LRAMVA		
68	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	Exhibit 9 - Section 9.3 Not Applicable
69	Current version of LRAMVA Work Form (Excel)	Not Applicable
An application for lost revenues should include:		Not Applicable
69	Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier	
69	Participation and Cost reports and detailed project level savings in Excel format made available by the IESO	Not Applicable
69	Other supporting evidence with an explanation and rationale should be provided to justify the eligibility any other savings from a program delivered by a distributor after April 15, 2019	Not Applicable
69	Personal information and commercially sensitive information removed, or if required, filed in accordance with OEB's Rules of Practice and Procedure and Practice Direction on Confidential Filings	Not Applicable
An application for lost revenues should also provide:		Not Applicable
70	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	
70	Statement confirming LRAMVA based on verified savings results supported by the distributors final Verified Annual Reports and Persistence Savings Report (both filed in Excel format)	Not Applicable
70	Statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation	Not Applicable
70	Summary table with principal and carrying charges by rate class and resulting rate riders	Not Applicable
70	Statement confirming recovery period; rationale provided for disposing the balance in the LRAMVA if one or more classes does not generate significant rate riders	Not Applicable
70	Details related to the approved CDM forecast savings from the last rebasing application	Not Applicable
70	Statement explaining how rate class allocations for actual CDM savings were determined by class and program for each year	Not Applicable
70	Statement confirming whether additional documentation was provided in support of projects that were not included in distributors final Verified Annual Reports and Participation and Cost Reports (Tab 8 of LRAMVA Work Form as applicable)	Not Applicable
70 & 71	If not already filed in support of a previous LRAMVA application, provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available - filed in Exel format	Not Applicable
71	For a distributor’s street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: explanation of the methodology to calculate street lighting savings, confirmation whether the street lighting projects received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings	Not Applicable
For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:		
71	Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application	Not Applicable
71	Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed	Not Applicable

2025 Cost of Service Checklist

LDC: Welland Hydro Electric System Corp.

EB-2024-0058

Date: August 23, 2024

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
71	Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings	Not Applicable
71	Confirmation that the distributor has received reports from the participating municipality that validate the number and types of bulbs replaced or retrofitted through the IESO program	Not Applicable
71	A table, in live Excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, types of bulb replaced or retrofitted, average demand per bulb)	Not Applicable
For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information:		Not Applicable
71	The third-party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate	Not Applicable
72	Rationale for net-to-gross assumptions used	Not Applicable
72	Breakdown of billed demand and detailed level calculations in live Excel format	Not Applicable
For program savings up to December 31, 2022 for projects completed after April 15, 2019, a distributor should provide the following:		Not Applicable
72	Related to CFF programs: explanation as to how savings have been estimated based on the available data (i.e., IESO's Participation and Cost Reports) and/or rationale to justify the eligibility of the program savings	Not Applicable
72	Related to programs delivered by a distributor through the Local Program Fund under the Interim CDM Framework: explanation and rationale to justify the eligibility of the additional program savings	Not Applicable
Continuing Use of the LRAMVA for New CDM Acitivities		
72	Indication of whether distributor is requesting the continued use of the LRAMVA for one or more activities related to distribution rate-funded CDM activities or LIP activities	WHESC is not requesting the continued use of the LRAMVA.
72	If requesting access to, or use of, the LRAMVA for these activities, demonstration of need for the LRAMVA (or similar mechanism), the proposed LRAMVA threshold, how it intends to support the tracking of lost revenues, and the nature of the documentation that it proposes to provide at the time of LRAMVA disposition	Not Applicable
72	Allocation of the CDM savings for both the LRAMVA and the load forecast provided by customer class and for both kWh and, as applicable to a customer class, kW. Document how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs	Not Applicable
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	Exhibit 2 - Section 2.10
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	Exhibit 2 - Section 2.10; WHESC 2025 Chapter2 Appendices 2024 08 23
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	Exhibit 2 - Section 2.10

Appendix 1-H: WHESC Updates/Amendments to Models

Adjustments made to Models

Chapter 2 Appendices

App.2-AB

- Cell R24 – Pulling from wrong reference. Updated formula by changing L to O

App.2-AA

- Adjusted formatting and inserted rows where insufficient number

App.2-BA

- D526 – Make zero instead of G463 (moved Capital contributions from 1995 to 2440)
- D525 – Made equal to G463 instead of G464 (moved Capital contributions from 1995 to 2440)
- J526 – Make zero instead of M463 (moved Capital contributions from 1995 to 2440)
- J525 – Made equal to M463 instead of G464 (moved Capital contributions from 1995 to 2440)
- D566 – Adjusted opening balance to account for MIST meters
- J566 – Adjusted opening balance to account for MIST meters

App.2-FC

- Cell AI58 – Changed Q to O – was pulling from incorrect cell
- Cell AJ58 – Changed Q to O - was pulling from incorrect cell

App.2-H

- C65 to E65 – updated to pull from row 25 instead of row 15 like other years
- Column H – Changed M to O
- Column I – Changed N to O

App.2-IB

- Insert columns (B and C) for 2017 and 2018
- Copied Headers
- Copied formulas to Columns B and C
- Hardcoded cells in B16 through G23 to represent average customer numbers
- Hardcoded row 36 to populate WMP data (included with Row 31)
- Row 31 added to the formula to subtract Row 36 (WMP reported with GS>50 for RRR but separated here)
- Hardcoded row 49 to populate WMP data (included with Row 44)
- Row 44 added to the formula to subtract Row 49 (WMP reported with GS>50 for RRR but separated here)
- Inserted Columns M and N for 2017 and 2018
- Copied formulas to Column N

App.2-JA

- D14, D15, E14 and E15 – added ‘+1’ like the rest of the years so that the proper amount is pulled from RRR data
- E36 – Was blank
    - Original formula: ‘=IF(S11<=RebaseYear,"",IF(S11=RebaseYear+1,IF(ISERROR((E35-$C$35)/$C$35),"",(E35-$C$35)/$C$35),IF(ISERROR((E35-D35)/D35),"",(E35-D35)/D35)))’

    - Revised formula: ‘=IF(S11=RebaseYear+1,IF(ISERROR((E35-$D$35)/$D$35),"",(E35-$D$35)/$D$35),IF(ISERROR((E35-D35)/D35),"",(E35-D35)/D35))
- F36 – Incorrect calculation (pulling from wrong prior year cells)
    - Original formula: ‘=IF(T11<=RebaseYear,"",IF(T11=RebaseYear+1,IF(ISERROR((F35-$C$35)/$C$35),"",(F35-$C$35)/$C$35),IF(ISERROR((F35-E35)/E35),"",(F35-E35)/E35)))
    - Revised formula: ‘=IF(T11<=RebaseYear,"",IF(T11=RebaseYear+1,IF(ISERROR((F35-$E$35)/$E$35),"",(F35-$E$35)/$E$35),IF(ISERROR((F35-E35)/E35),"",(F35-E35)/E35)))
- S18 to V18 – Updated to pull from Row 25 instead of Row 22
- S20 – Was blank. Updated formula
    - Original formula: ‘=IF(S11<=RebaseYear, 0, S18-S19)’
    - Revised formula: ‘=S18-S19’
- T22 – was calculating the incorrect percentage (0%). Updated formula
    - Original formula: ‘=IF(S11<=RebaseYear, 0, IF(T11=RebaseYear+1, IF(ISERROR(T21/$Q$20), "", T21/$Q$20),IF(ISERROR(T21/S20), "", T21/S20)))’
    - Revised formula: ‘=IF(T11<=RebaseYear, 0, IF(T11=RebaseYear+1, IF(ISERROR(T21/$Q$20), "", T21/$Q$20),IF(ISERROR(T21/S20), "", T21/S20)))’
- Copied formula from C21 to D21 for 2017 Last Rebating Year Actuals Admin & General
- E21 - Incorrect reference
    - Original formula: =VLOOKUP('LDC Info'!$E$14 & " Administrative and General Expenses " & LEFT(E12,4),'OM&A_Expenses'!$C:$F,4,FALSE)+VLOOKUP('LDC Info'!$E$14 & " Administrative and General Expenses " & LEFT(E12,4),'OM&A_Expenses'!$C:$G,5,FALSE)
    - Revised Formula: =VLOOKUP('LDC Info'!$E$14 & " Administrative and General Expenses " & LEFT(E12,4)+1,'OM&A_Expenses'!$C:$F,4,FALSE)+VLOOKUP('LDC Info'!$E$14 & " Administrative and General Expenses - LEAP " & LEFT(E12,4)+1,'OM&A_Expenses'!$C:$G,4,FALSE)

App.2-JB

- Inserted 2 rows (Row 15 and Row 16) in order to show Wages & Benefits separately
- Added subtotal for opening balances on Row 17
- Adjusted totals in Rows 44, 45 and 46 to account for subtotal of changes in Wages & Benefits and non-Wages & Benefits expense
- Adjusted references in D15 to K15 to pull from prior year Row 44
- Added references in D16 to K16 to pull from prior year Row 45

App.2-JC

- Inserted/deleted rows to accommodate the appropriate number of OM& Programs
- Copied formulas in Columns M & N for the newly inserted rows

App.2-K

- Added rows under Row 29 to allow for further granularity
- Added subtotal to Row 29, and additional subtotals/totals on Rows 32 and 38

App.2-N

- Inserted additional rows in tables as required

App.2-OB

- J61 to J64 – hard coded interest to equal actual interest for that year
- J82 – hard coded interest to equal actual interest for that year
- J139 and J140 – hard coded interest to equal actual interest for that year

App.2-R

- Added 2 additional rows to break out A(2) further
- Copied formula down to I18 and I19 (newly inserted rows)
- Adjusted formula on Row 21 to add the 2 newly inserted rows (part of A(2) total)

App.2-ZA

- D32 – changed from Account 4035 to 4010 (used row for WMP, not embedded generator)
- J32 and K32 – changed rate to zero – doesn't apply to WMP
- K58 – changed rate to zero – doesn't apply to WMP
- to Column N

2025 RTSR Model

Tab 4

- Inserted a column to break out 2024 year from January to June and July to December (rate change mid-year)

Tariff Schedule and Bill Impact Model

Tab 3

- OEB changed E39 on Regulatory Charges tab to the new inflation of 3.6% from 4.8%

PILs Model

B0 Pils Tax Provision Bridge

- Updated formula in E13 to equal Column D – Small Business Rate not applicable

T0 Pils Tax Provision Test

- Updated formula in E13 to equal Column D – Small Business Rate not applicable

DVA Continuity

2b. Continuity Schedule

- F49 - Unlocked to key balance
- F83 – Unlocked to key balance
- F105 - Unlocked to key balance
- K105 - Unlocked to key balance
- P50 - Unlocked to key balance
- U50 - Unlocked to key balance

5. Allocation of balances

- Row 75 – Added Account 1557 Meter Cost Deferral Account as it was missing from list

7. Rate Rider Calculations

- Added Table for Account 1557 – Meter Cost Deferral Account – not originally included
- Added table for Account 1580 CBR Class B Rate Rider – not originally included

Cost Allocation

I3

- A334 – Changed Account 4710 to Account 4707

O5

- A123 - Changed Account 4710 to Account 4707

E4

- A124 - Changed Account 4710 to Account 4707

O4

- A123 - Changed Account 4710 to Account 4707