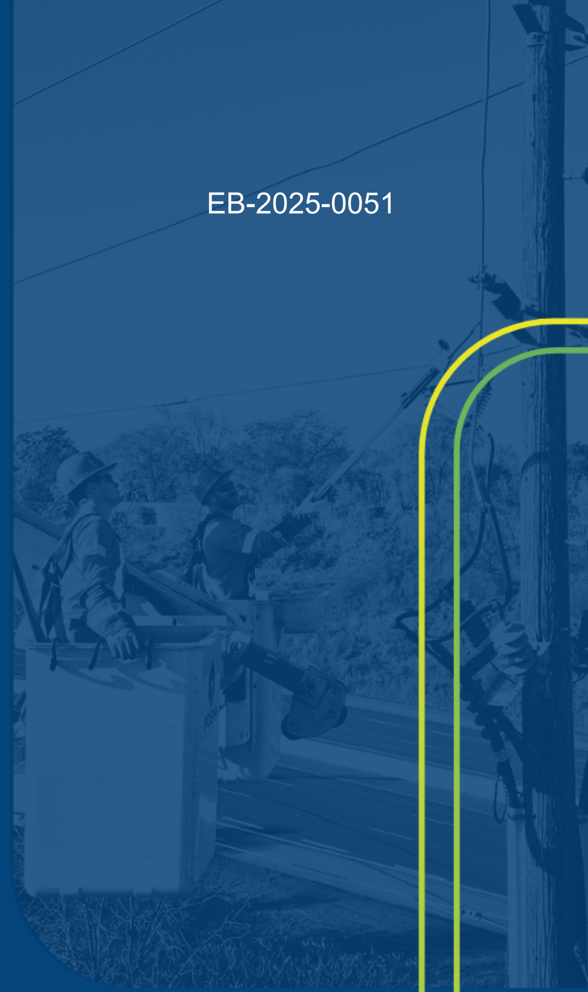
EB-2025-0051



Burlington Hydro Inc.

2026 Cost of Service Application

EB-2025-0051

April 16, 2025

EXHIBIT 1

APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS

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EXHIBIT 1 – APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS

1.0 INTRODUCTION

Burlington Hydro Inc.'s ("BHI's") 2026 Cost of Service Application (EB-2025-0051) (the "Application") describes how BHI will develop, manage, operate and maintain its distribution system to provide safe, secure, reliable, efficient, and cost-effective service to its customers. The period for this Application covers six years with a five-year historical period beginning with 2021 and ending with the 2025 Bridge Year; and a one-year forecast period - the 2026 Test Year. The Distribution System Plan ("DSP") covers ten years, including a five-year forecast period beginning with the 2026 Test Year and ending in 2030. BHI's last Cost of Service application and DSP was filed October 30, 2020 for rates effective May 1, 2021.

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

- Exhibit 1 - Application Overview and Administrative Documents
- Exhibit 2 - Rate Base and Capital (including the DSP)
- 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/Sufficiency
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts

BHI has prepared this Application in accordance with the following:

- the Ontario Energy Board's ("OEB's") *Chapter 2 Cost of Service Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications* issued December 9, 2024 (the "Chapter 2 Filing Requirements");
- the OEB's *Chapter 5 Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications* issued December 9, 2024 (the "Chapter 5 Filing Requirements"); and
- the OEB's *Handbook for Utility Rate Applications* issued October 13, 2016.

BHI has not deviated from these filing requirements and provides a checklist of the filing requirements as Appendix A to this Exhibit 1, which identifies the specific reference in the Application where relevant information is provided.

This Exhibit 1 provides information relating to the overview and administration of this Application and contains eleven sections including this introductory **Section 1.0**. **Section 1.1** provides a Table of Contents listing the major sections and subsections of the Application. **Section 1.2** provides an Executive Summary to identify key elements of BHI's proposals and the Business Plan underpinning this Application. **Section 1.3** includes administrative information related to this Application. **Section 1.4** includes an overview of BHI's distribution system. **Section 1.5** discusses how BHI informed its customers of the proposals being considered for inclusion in the Application, and the value of those proposals to customers. **Section 1.6** discusses BHI's performance measurement and improvement targets. **Section 1.7** discusses BHI's approach to innovation and how this approach has shaped the Application. **Section 1.8** provides BHI's financial information. **Section 1.9** discusses distributor consolidation. **Section 1.10** discusses the impacts of the COVID-19 pandemic on this Application. This Exhibit is organized using the same section headings indicated in the Chapter 2 Filing Requirements.

1.1 APPLICATION TABLE OF CONTENTS

BHI provides a Table of Contents listing the major sections and subsections of its Application below.

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7.1.2 Specific Customer Class(es)
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1.2 APPLICATION SUMMARY AND BUSINESS PLAN

1.2.1 Introduction

BHI provides a summary of the key elements of its Application in this Section 1.2. These include the business, capital and operating plans that underpin the Application and the corresponding funding that is required to develop, manage, operate, and maintain its distribution system to provide safe, secure, reliable, efficient, and cost-effective service to its customers. BHI's plans are an outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. BHI developed its plans to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

1.2.2 About BHI

BHI is a municipally owned local distribution company ("LDC") serving the City of Burlington ("the City"), with a total licensed service area of 188 square kilometres and a customer base of approximately 69,000 customers (consisting of Residential, Commercial, Street Light, and Unmetered Scattered Load customers). BHI delivers electricity into the community through a network of approximately 1,500 kilometres of medium-voltage distribution lines and 32 substations.

BHI is one of two subsidiary companies wholly owned by the City of Burlington through a holding company, Burlington Enterprises Corporation ("BEC"). BEC's other subsidiary is an unregulated electricity services company - Burlington Electricity Services Inc. ("BESI").

1.2.3 BHI's Business Plan Underpinning the Application

In accordance with the OEB's Handbook for Utility Rate Applications[1], BHI prepared a formal Business Plan that outlines BHI's overall strategy and goals. The Business Plan was approved by BHI's Board of Directors on November 12, 2024 and is attached as Appendix B to this Exhibit 1.

[1] Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016

BHI's goals that informed this Application are as follows:

- Provide exceptional internal and external customer service across the organization.
- Deliver electricity safely and reliably by renewing deteriorated components of the system most at risk of failure.
- Provide comprehensive public safety awareness education/communications and maintain a culture that prioritizes safety for employees and customers.
- Upgrade the distribution system by hardening the grid to respond to increasing extreme weather events.
- Enhance support for Distributed Energy Resources (DERs) integration and electric vehicle (EV) infrastructure to support a sustainable energy transition.
- Respond to and prepare for increased demand and customer growth in specific areas of our service territory.
- Continuous investment in technology that helps reduce electricity distribution costs, provides consumer choice and creates business value.
- Invest in workforce planning and training programs to equip employees with skills for a digital environment. Focus on talent acquisition, development, and retention to build a future ready workforce.
- Deliver electricity at prudent and value-based distribution rates.

1.2.4 Application Summary

In the sections below, BHI provides a brief summary of its Application, comprised of a high-level overview of the key elements driving the proposals in this Application, including customer needs and preferences and a description of major system challenges.

1.2.4 A Revenue Requirement

BHI’s proposed service requirement for the 2026 Test Year is $52,840,656 as identified in Table 1 below. This represents an increase of $15,844,464 and an average annual increase of 7.4% as compared to the service revenue requirement approved in BHI's 2021 Cost of Service application.

Table 1 – 2026 Test Year Revenue Requirement vs. 2021 Cost of Service application

Description	2021 Cost of Service	Proposed 2026 Test Year	$ Increase/ (Decrease)	% Increase/ (Decrease)	CAGR % Increase/ (Decrease)
OM&A Expenses	$20,557,775	$30,040,101	$9,482,326	46.1 %	7.9 %
Depreciation Expense	$8,146,553	$10,046,886	$1,900,333	23.3 %	4.3 %
Property Taxes	$341,790	$375,892	$34,102	10.0 %	1.9 %
Payment in Lieu of Taxes (PILs)	$398,574	$931,830	$533,256	133.8 %	18.5 %
Deemed Interest Expense	$2,638,061	$4,800,334	$2,162,273	82.0 %	12.7 %
Return on Deemed Equity	$4,913,439	$6,645,614	$1,732,175	35.3 %	6.2 %
Total Service Revenue Requirement	**$36,996,192**	**$52,840,656**	**$15,844,464**	**42.8 %**	**7.4 %**
Other Operating Revenue	$(3,079,167)	$(4,355,525)	$(1,276,358)	41.5 %	7.2 %
Total Base Revenue Requirement	**$33,917,025**	**$48,485,131**	**$14,568,106**	**43.0 %**	**7.4 %**

The drivers of this increase are:

- an increase in Operating, Maintenance and Administration expenses (“OM&A”) of $9,482,326, the rationale for which is provided below in Section 1.2.4 D and in further detail in Sections 4.1, 4,2 and 4.3 of Exhibit 4;
- an increase in Deemed Interest Expense contributing $2,162,273, discussed in further detail in Section 6.1.7.3 of Exhibit 6. This increase is attributable to an increase in the BHI's weighted average cost of debt of 1.35%; and an increase in rate base as discussed in Section 1.2.4 C.2 below;
- an increase in Return on Deemed Equity contributing $1,732,175, discussed in further detail in Section 6.1.7.3 of Exhibit 6. This increase is attributable to an increase in BHI's deemed Return on Equity from 8.34% to 9.00%; and an increase in rate base as discussed in Section 1.2.4 C.2 below; and
- an increase in Depreciation contributing $1,900,333 discussed in further detail in Section 2.4 of Exhibit 2.

1.2.4 B Load Forecast Summary

BHI used a multivariate regression model, consistent with its last rebasing application, to determine a class specific, weather-normalized load forecast and customer/connection forecast for the 2026 Test Year. Further details are provided in Exhibit 3 of this Application.

BHI provides a high-level summary of its load forecast for the 2026 Test Year as compared to its 2021 Cost of Service application in Table 2 to Table 4 below.

Forecasted energy sales for the 2026 Test Year are 1,489,025,881 kWh which represents an increase of 5,719,903 kWh or 0.4% as compared to the 2021 OEB-approved kWh forecast, as identified in Table 2 below.

Table 2 – Consumption Forecast (kWh)

Rate Class	Consumption (kWh)					
	2021 Cost of Service	2024 Weather Normal Actuals	2025 Bridge Year	2026 Test Year	Incr/(Decr) 2026 vs. 2021 CoS kWh	Incr/(Decr) vs. 2021 CoS %
Residential	520,340,552	542,906,523	551,459,828	556,998,473	36,657,921	7.0 %
GS<50 kW	156,917,865	170,285,702	169,765,570	172,548,369	15,630,504	10.0 %
GS>50 kW	797,368,549	801,209,850	762,298,639	750,558,930	(46,809,619)	(5.9)%
Street Lights	5,543,828	5,595,609	5,601,815	5,608,031	64,203	1.2 %
USL	3,135,184	3,283,470	3,297,742	3,312,078	176,894	5.6 %
Total	**1,483,305,978**	**1,523,281,153**	**1,492,423,594**	**1,489,025,881**	**5,719,903**	**0.4 %**

Forecasted energy demand (GS>50 kW and Street lighting customers) for the 2026 Test Year is 2,033,102 kW which represents a decrease of (142,670) kW or (6.6)%) as compared to the 2021 OEB-approved kW forecast, as identified in Table 3 below.

Table 3 – Demand Forecast (kW)

Rate Class	Demand (kW)					
	2021 Cost of Service	2024 Weather Normal Actuals	2025 Bridge Year	2026 Test Year	Incr/(Decr) 2026 vs. 2021 CoS CoS kW	Incr/(Decr) vs. 2021 CoS %
GS>50 kW	2,160,311	2,079,177	2,046,862	2,017,430	(142,881)	(6.6)%
Street Lights	15,461	15,637	15,655	15,672	211	1.4 %
Total	**2,175,772**	**2,094,814**	**2,062,517**	**2,033,102**	**(142,670)**	**(6.6)%**

BHI's forecasted customer/connection count for the 2026 Test Year is 87,827 which represents an increase of 1,366 customers/connections or 1.6% as compared to the 2021 OEB-approved kWh forecast. Customer/connection counts are based on the average for the year, as identified in Table 4 below.

Table 4 – Customer/Connection Forecast

Rate Class	Customers/Connections					
	2021 Cost of Service	2024 Weather Normal Actuals	2025 Bridge Year	2026 Test Year	Incr/(Decr) 2026 vs. 2021 CoS CoS kW	Incr/(Decr) vs. 2021 CoS %
Residential	62,056	62,564	62,841	63,119	1,063	1.7 %
GS<50 kW	5,564	5,712	5,768	5,823	259	4.7 %
GS>50 kW	1,004	965	959	952	(52)	(5.2)%
Street Lights	17,283	17,310	17,329	17,348	65	0.4 %
USL	554	579	581	584	30	5.4 %
Total	**86,461**	**87,130**	**87,477**	**87,827**	**1,366**	**1.6 %**

1.2.4 C Rate Base and DSP

<u>1.2.4 C.1 Major Drivers of the DSP</u>

BHI's DSP, attached as Appendix A to Exhibit 2, was developed to address and appropriately balance the needs and preferences of its customers; its distribution system requirements; significant population, employment and housing growth; technological advancements; and relevant public policy objectives. BHI's investment plans are the outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. The major drivers of BHI's DSP are the following requirements:

Invest in Reliability and Resiliency

- Address declining reliability, due to the failure of aging infrastructure, through increased asset renewal and refurbishment. Further details are provided below in Section 1.2.4 C.1.1 below.
- Ensure the distribution system is prepared for the impacts of climate change through strategic asset renewal and complementary grid hardening efforts as described in Section 5.2.1.3 of the DSP. The impact of climate change is discussed in further detail below in Section 1.2.4 C.1.2.
- Expand the 'Intelliteam Smart Grid Automatic Restoration System' network through continued investment in intelligent switches and other grid automation investments as identified in Section 5.4.1.2 of the DSP. These technologies can integrate seamlessly with Advanced Distribution Management System ("ADMS") functionality, automating routine grid operations and expediting system restoration during abnormal conditions.

Deliver Capacity to Meet Customer and Load Growth

- Ensure the distribution system can meet the demands of public policy changes (e.g. More Homes Built Faster Act, 2022), including with respect to the rapidly evolving housing needs in BHI's service territory, such as development around Major Transit Station Areas ("MTSAs"), which will require additional capital investments to build and connect. BHI's population is expected to increase by 16.0% from 186,948 in 2021 to 216,800 in 2031 as identified in Table 10 below.
- Accommodate third-party requests related to infrastructure renewal and expansion projects that require BHI to relocate its existing infrastructure. BHI is obligated by the

Public Service Works on Highways Act[2] to accommodate these third-party requests in a fair and reasonable manner.

- Respond to evolving policy and customer expectations in response to the energy transition, such as connecting electric vehicles and electrification of home heating and transportation.
    - 100% of new light-duty vehicle sales must be zero-emissions by 2035. Medium-and-heavy-duty vehicles are converting to electric, including the conversion of the City of Burlington Transit's fleet of buses. Annual energy consumption is expected to increase exponentially as identified in the Burlington Distribution Sustainability Report.[3]
    - Air source heat pumps are expected to be in 40% of residential buildings and 30% of commercial buildings by 2050, and ground source heat pumps are expected to be in 20% of residential and 25% of commercial buildings by 2050.[4]

Electrification of transit and home heating requires additional capital expenditures to support grid modernization, manage peak demand, integrate renewable energy and ensure the grid can handle the growing demand for electricity.

Modernize BHI's Grid and Operations

- Transition to the next generation Advanced Meter Infrastructure ("AMI") 2.0 system with real-time integration with BHI's Outage Management System ("OMS") and Customer Information System ("CIS"). Further details are provided in Section 5.4.1 of the DSP.
- Upgrade BHI's Supervisory Control and Data Acquisition ("SCADA") system including implementation of an ADMS to modernize grid management capabilities in response to increased demand, electrification, and DER penetration as set out in Section 2.7 of Exhibit 2.

[2] Public Service Works on Highways Act, R.S.O. 1990, c. P.49
[3] Figure 7, Burlington Distribution Sustainability Report, June 19, 2024
[4] Ibid, Figure 9

- Continue investment in cyber security tools and platforms to enhance cyber security readiness in accordance with the Ontario Cyber Security Framework ("OCSF")[5] and the OEB's Ontario Cyber Security Standard[6].
- Modernize aging fleet assets including a strategic transition to EVs as described in Section 5.4.1 of the DSP.

BHI provides further details on the Deteriorating Condition of its Distribution Infrastructure and Climate Change in Sections 1.2.4 C.1.1 and 1.2.4 C.1.2 below.

1.2.4 C.1.1 Deteriorating Condition of Distribution Infrastructure

As supported by BHI's Asset Condition Assessment ("ACA"), a material percentage (17%) of BHI's asset base is in Very Poor, Poor or Fair condition, indicating at a minimum that replacement may be required depending on the asset's criticality, as identified in Section 5.3.2.2 of the DSP. Further, assets in Fair condition will continue to deteriorate into Poor or Very Poor condition over the Application horizon.

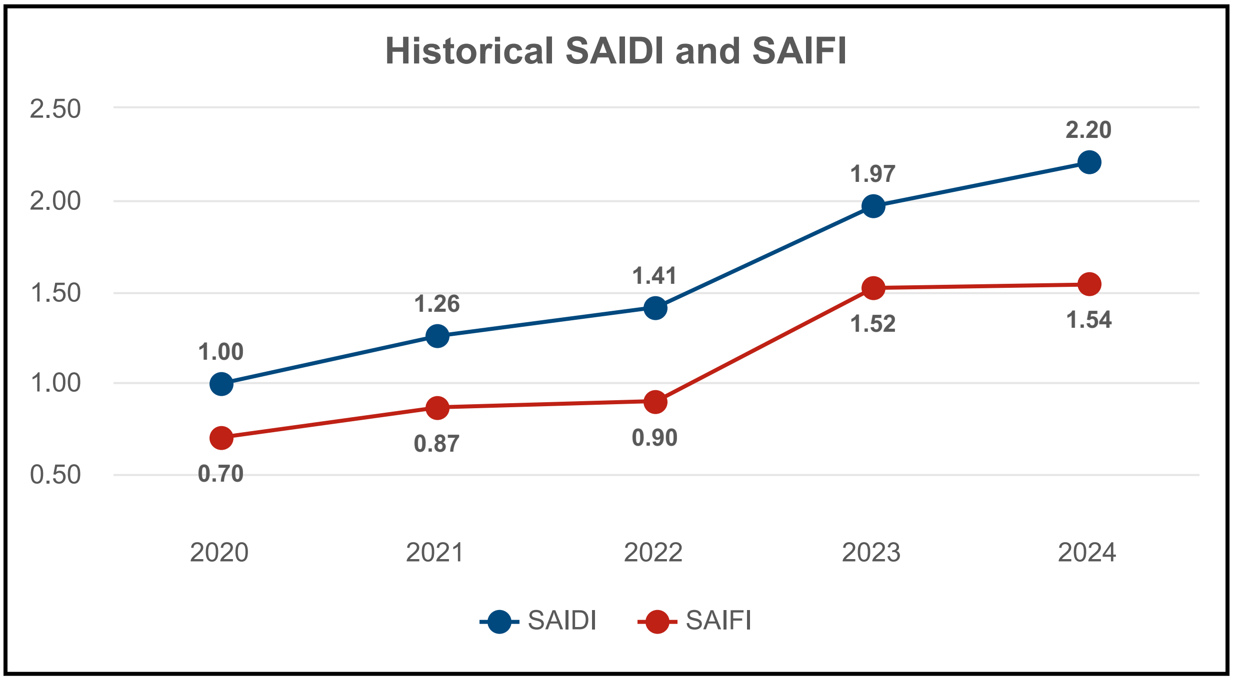
BHI is proposing a proactive replacement program for certain assets, as identified in Table 5.3-15 of the DSP, in order to address those assets currently in Poor or Very Poor condition, while mitigating the risk of an increasing renewal backlog from the group of assets currently in Fair condition. An increase in the backlog of assets past useful life would result in deterioration in reliability, safety, and other outcomes driven by asset failure.

BHI has already experienced a significant deterioration in reliability since its last Cost of Service application as identified in Figure 1 below - defective equipment is one of the largest contributors to the frequency (35%), and duration (38%) of BHI's outages.

[5] Ontario Cyber Security Framework (OCSF) v 1.1, December 7, 2023

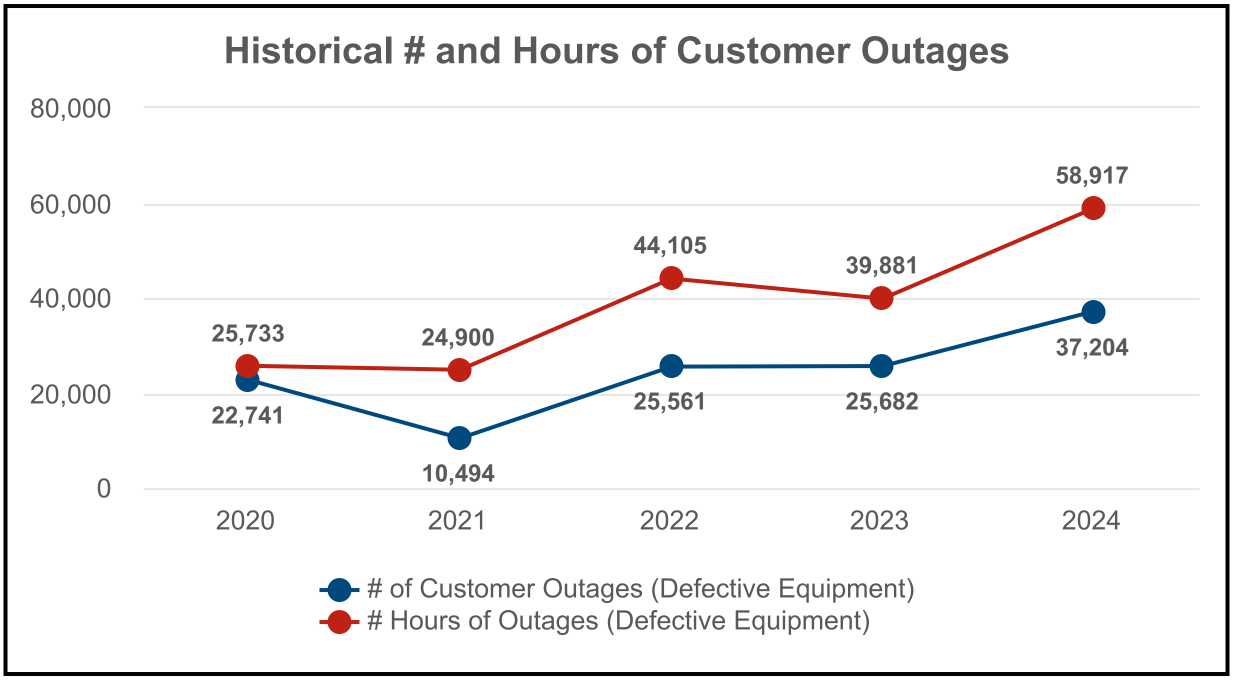
[6] Ontario Cyber Security Standard, March 27, 2024

Figure 1 - Historical SAIDI and SAIFI



The number of customer outages due to defective equipment alone increased by 255% from 10,494 in 2021 to 37,204 in 2024 as identified in Figure 2 below. In addition to service disruptions, which can lead to customer dissatisfaction, and increased repair and maintenance costs, there is an accelerated risk associated with defective equipment which can pose safety hazards for employees and customers.

Figure 2 - Outages due to Defective Equipment



<u>1.2.4 C.1.2 Climate Change</u>

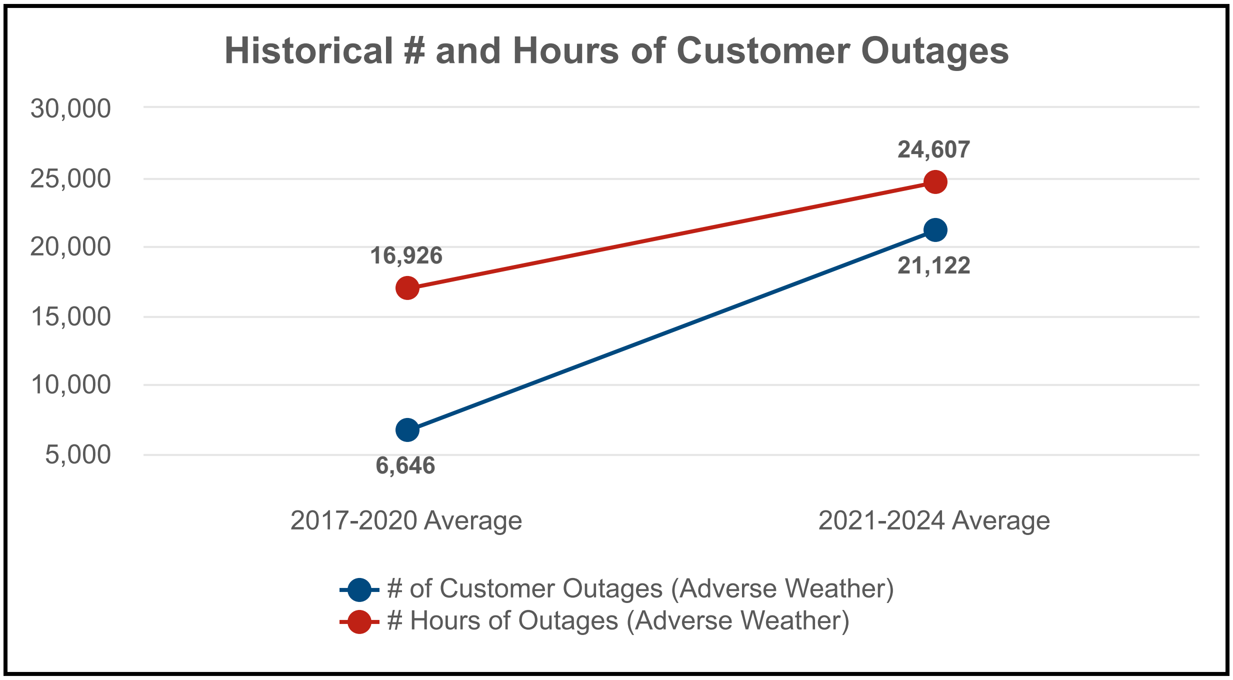
In addition to reliability challenges posed by a backlog of deteriorating and obsolete equipment, increasingly frequent adverse weather events have put additional reliability pressures on BHI's distribution system. The Government of Ontario's *Vulnerability Assessment for Ontario's Electricity Distribution Sector Report*[7] recognizes that "climate change is already having significant impacts on the province of Ontario and is guaranteed to affect the province in years and decades to come. Changing weather patterns as a result of climate change will have important implications for the energy sector".

Outage trends due to adverse weather, as experienced by BHI, are identified in Figure 3 below. The number of customer outages in the four year period from 2021-2024 increased by 218% over the previous four year period (2017-2020). These circumstances drive the need for investments to facilitate and improve system resiliency and BHI's ability to respond to adverse weather events. Proposed investments in the renewal of legacy assets, through reinforcement and replacement, will contribute to system hardening by improving asset health and introducing updated equipment design and construction standards that are better suited to the changing operating environment. In addition to affecting system reliability, outages due to adverse

[7] https://www.ontario.ca/page/vulnerability-assessment-ontarios-electricity-distribution-sector

weather have a direct impact on OM&A expenditures - they require immediate corrective action to repair and restore assets to their normal operating condition to reduce safety risk to crews and the public, and restore power.

Figure 3 - Outages due to Adverse Weather (excluding Loss of Supply/MEDs)



1.2.4 C.2 Rate Base Summary

BHI's proposed rate base in the 2026 Test Year is $184,600,382, which is $37,315,038 or 25.3% higher than the rate base of $147,285,343 approved in BHI's 2021 Cost of Service application, as identified in Table 5 below.

Table 5 – 2026 Test Year vs. 2021 OEB Approved Rate Base

Description	2021 CoS (EB-2020-0007)	2026 Test Year	Variance $ Incr/(Decr)	Variance % Incr/(Decr)
Net Fixed Assets				
Gross Fixed Assets (Average)	$309,536,105	$378,590,894	$69,054,790	22.3 %
Accumulated Depreciation (Average)	$177,259,444	$209,633,086	$32,373,642	18.3 %
Net Fixed Assets (Average)	**$132,276,661**	**$168,957,808**	**$36,681,148**	**27.7 %**
Allowance for Working Capital				
Cost of Power	$179,216,197	$178,151,648	$(1,064,548)	(0.6)%
Distribution Expenses	$20,899,565	$30,415,993	$9,516,428	45.5 %
Total CoP/Distribution Expenses	**$200,115,762**	**$208,567,641**	**$8,451,879**	**4.2 %**
Working Capital Allowance %	7.5%	7.5%	—%	0
Working Capital Allowance	**$15,008,682**	**$15,642,573**	**$633,891**	**4.2 %**
Rate Base				
Total Rate Base	**$147,285,343**	**$184,600,382**	**$37,315,038**	**25.3 %**

The increase in rate base from BHI's 2021 Cost of Service application is due to an increase in average net fixed assets of $36,681,148 and in the Working Capital Allowance ("WCA") of $633,891.

The increase is average net fixed assets is attributable to in-service additions up to 2024 ($15,401,917) and proposed capital additions in 2025 and 2026 ($21,279,230). Approximately half of the capital additions were and will be related to mandatory investments to provide service to connections, upgrades, and relocations. BHI also supported, and will continue to support multi-unit residential construction, new subdivisions, and third-party infrastructure projects including expansions and infrastructure relocations. BHI has and will continue to invest in proactive and reactive replacement of assets such as wood poles, underground primary cables, distribution transformers, switches, and municipal substation ("MS") assets to ensure a safe and reliable distribution system and mitigate the risks of unplanned outages due to asset failures.

BHI implemented unforeseen mandatory projects, such as the replacement of revenue metering at the Burlington Transformer Station ("TS") to comply with safety regulations, and meter resealing/reverification to comply with Measurement Canada regulations.

It continued investments to upgrade its legacy CIS, replaced its OMS to enhance customer service and operational efficiency, and integrated its Geographic Information System ("GIS") with its OMS.

Further investments included and will include renovating and replacing deteriorated areas of BHI's head office and substation buildings, the acquisition of a parcel of land for continued use in service of BHI's electricity distribution operations, and replacing small and large fleet vehicles as warranted based on their condition.

Further details are provided in Section 2.2.1 of Exhibit 2 of this Application.

The increase in WCA of $633,891 is attributable to higher Cost of Power ("COP"), and distribution expenses such as operations and maintenance, billing, collections and administration expenses ("OM&A"). Further details on COP are provided in Sections 2.2 and 2.5 of Exhibit 2 and further details on OM&A are provided in Exhibit 4.

1.2.4 C.3 Capital Expenditure Summary

BHI's proposed capital expenditures in the 2026 Test Year are $24,271,845, which is $10,781,712 or 79.9% higher than the 2021 OEB-approved capital expenditures of $13,490,133 as identified in Table 6 below.

Table 6 – 2026 Test Year vs. 2021 OEB Approved Capital Expenditures

Description	2021 CoS (EB-2020-0007)	2026 Test Year	Variance $ Incr(Decr)	Variance % Incr/(Decr)
System Access	$29,645,598	$35,694,524	$6,048,926	20.4 %
System Renewal	$3,055,000	$6,180,741	$3,125,741	102.3 %
System Service	$200,000	$510,000	$310,000	155.0 %
General Plant	$1,197,870	$2,594,880	$1,397,010	116.6 %
Gross Expenditures	**$34,098,468**	**$44,980,145**	**$10,881,677**	**31.9 %**
Capital Contributions	$(20,608,334)	$(20,708,300)	$(99,965)	0.5 %
Net Capital Expenditures	**$13,490,133**	**$24,271,845**	**$10,781,712**	**79.9 %**

The increase in capital expenditures from BHI's 2021 Cost of Service application to the 2026 Test Year is driven by higher expenditures across all four spending categories: System Access, System Renewal, System Service and General Plant.

Higher System Access expenditures in the 2026 Test Year as compared to the 2021 Cost of Service application are driven by non-discretionary projects including (i) development around MTSAs to supply new infrastructure to serve new residential, commercial and industrial customers as discussed in Section 5.4.1.2.1 of the DSP, (ii) a large-scale smart meter replacement project, commencing in 2026, to comply with the Measurement Canada regulations discussed in Section 5.4.1.2.1 of the DSP and (iii) customer-driven underground connections, upgrades and relocations.

Higher System Renewal expenditures in the 2026 Test Year as compared to the 2021 Cost of Service application are driven by the requirement to renew assets in Very Poor or Poor condition, as identified in BHI's ACA[8]. This includes accelerating the pace of (i) replacing or refurbishing underground cables and wood poles to mitigate failure risk and the consequent negative impact on reliability; and (ii) replacing station relays to mitigate failure risk and the risks associated with technological obsolescence. These programs are discussed further in Section 5.4.1.2.2 of the DSP.

Higher System Service expenditures in the 2026 Test Year as compared to the 2021 Cost of Service application are driven by the conversion and upgrade of BHI's Advanced Metering Infrastructure ("AMI") collectors and repeaters which are used to collect and remit meter data for billing purposes. This upgrade is critical to ensure that communication is maintained with the new meters replaced as part of the smart meter replacement project discussed above. This program is discussed further in Section 5.4.1.2.3 of the DSP.

Higher General Plant expenditures in the 2026 Test Year as compared to the 2021 Cost of Service application are driven by (i) vehicle expenditures for the replacement of large and small trucks to ensure reliability and operational effectiveness; (ii) building expenditures including renovations of deteriorated areas of BHI's head office, replacing end of life Heating, Ventilation,

[8] DSP Appendix I - 2024 Asset Condition Assessment Report

and Air Conditioning ("HVAC") units, and expansion and paving of the south parking lot; and (iii) IT/OT upgrades including the replacement of end-of-life servers that will no longer be supported, and implementation of efficiency tools such as SharePoint, inventory management and budgeting software. Further details are provided in Section 5.4.1.2.4 of the DSP.

1.2.4 D Operations, Maintenance and Administration Expense

1.2.4 D.1 Total OM&A

BHI is proposing to recover OM&A of $30,040,101 through distribution rates, which represents an increase of $9,482,326 or 7.9% per annum on average as compared to BHI's 2021 Cost of Service application, as identified in Table 7 below.

Table 7 – OM&A 2026 Test Year vs. 2021 OEB-approved

Description	2021 Cost of Service	2026 Test Year	2026 vs. 2021 CoS Incr/ (Decr)	2026 vs. 2021 OEB approved CAGR
Total OM&A excluding Property Taxes	$20,557,775	$30,040,101	$9,482,326	7.9 %

This represents an increase of $8,912,701 as compared to 2021 Actuals of $21,127,400 as identified in Table 8 below.

Table 8 - OM&A 2026 Test Year vs. 2021 Actuals

Description	2021 Actuals	2022 Actuals	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year	2026 vs. 2024 Actuals Incr/(Decr) $	2026 Test Year vs. 2021 Actuals		
								Total Incr/ (Decr)	Incr/(Decr) Due to Inflation	Incr/(Decr) Due to Operational Factors
Total Salaries and Benefits	$13,713,177	$13,559,951	$14,389,647	$14,619,071	$15,971,010	$18,292,369	$3,673,299	$4,579,192	$2,332,437	$2,246,755
Operational Changes	$2,597,600	$2,779,924	$3,167,326	$3,650,210	$3,977,173	$4,292,697	$642,487	$1,695,096	$532,312	$1,162,784
Policy/Business Changes	$2,789,977	$3,105,484	$2,961,648	$3,418,950	$3,777,736	$4,104,441	$685,491	$1,314,464	$571,735	$742,729
Technological Changes	$1,430,568	$1,604,093	$1,866,786	$1,736,736	$2,076,996	$2,279,832	$543,096	$849,264	$293,159	$556,105
Other Costs	$596,078	$576,732	$694,028	$409,688	$957,055	$1,070,762	$661,074	$474,684	$122,151	$352,533
Total	**$21,127,400**	**$21,626,185**	**$23,079,436**	**$23,834,655**	**$26,759,971**	**$30,040,101**	**$6,205,447**	**$8,912,701**	**$3,851,794**	**$5,060,907**
Total Ex Salaries and Benefits	**$7,414,223**	**$8,066,233**	**$8,689,788**	**$9,215,584**	**$10,788,961**	**$11,747,732**	**$2,532,148**	**$4,333,508**	**$1,519,357**	**$2,814,152**

Approximately 43% or $3,851,794 of this $8,912,701 increase is due to inflationary increases, primarily in salaries and benefits. The remaining 57% or $5,060,907 is a result of changes in BHI’s operations, some of which are outside of its control as discussed in Section 1.2.6 D.2 below.

1.2.4 D.2 Summary of Overall Drivers and Cost Trends

The increase in costs from BHI's 2021 Cost of Service application to the 2026 Test Year is driven by inflation; and a number of operational, policy, business environment, and technological changes as identified in Table 8 above and Table 9 below.

Table 9 - Summary of Overall Drivers

Description	$
2021 Cost of Service	**$20,557,775**
Salaries & Benefits including Incentives	$6,280,316
Vegetation Management	$632,222
Software Licensing, Support and Maintenance	$321,339
Contracted Labour	$269,755
Insurance	$220,585
Asset Inspection, Testing & Scheduled Maintenance	$181,871
Professional Fees	$179,119
Technology Consulting Services	$179,000
Locates	$133,695
Consulting Fees	$123,135
OEB Regulatory Costs	$117,889
Subscriptions/Memberships	$110,620
Training	$91,525
Office Operating/Maintenance Costs	$86,776
Hosting Services	$75,000
Other	$479,478
Net Change	**$9,482,326**
2026 Test Year	**$30,040,101**

1.2.4 D.2.1 Salaries and Benefits

There are several factors which have influenced and continue to influence BHI's staffing levels over the 2021 to 2026 period, resulting in the need to increase salaries and benefits beyond inflation. BHI's workforce is expected to undergo significant change as a result of the following internal and external factors:

- The Ontario energy sector is undergoing transformational change driven by changing legislative and regulatory requirements, climate change, technological advancements, provincially-mandated housing targets, and evolving consumer expectations. These changes, some of which are identified below, create both challenges and opportunities for BHI and the broader industry, and require adequate resources to address and accomplish the following initiatives:

- The Ministry of Energy and Electrification ("MENDM) issued its renewed Letter of Direction to the OEB on December 19, 2024[9] which included a number of expectations/directives related gird reliability, grid modernization and electrification. These are discussed in further detail identified in Section 4.1.2 of Exhibit 4.
- The OEB, as of the time of filing, had 32 active policy initiatives and consultations[10], 27 of which were launched after BHI's last Cost of Service application. These initiatives, while improving sector resiliency, reliability, and customer choice, among other benefits, require additional resources to implement and are discussed in further detail identified in Section 4.1.2.1 of Exhibit 4.
- BHI has experienced a significant deterioration in reliability since its last Cost of Service application as identified in Figure 1 above, primarily driven by defective equipment and adverse weather as identified in Figure 2 and Figure 3 respectively. These reliability trends have a direct impact on OM&A expenditures as outages due to defective equipment and adverse weather require immediate corrective action to repair and restore assets to their normal operating condition to reduce safety risk to crews and the public, and restore power. This is discussed in further detail in Section 4.3.0.7 of Exhibit 4.
- The overall technology landscape has changed significantly since BHI's last Cost of Service resulting in the need for BHI to increase its Full-Time Equivalent ("FTE") complement. These changes are discussed further in Section 1.2.4 D.2.4 of this Exhibit 1.
- The City of Burlington's Vision 2040 Strategic Plan[11] anticipates significant population, employment and housing growth as identified in Section 5.3.2.1.6 of BHI's DSP, which will require additional BHI resources to build, connect, bill and service as discussed in Section 4.3.1.1 of Exhibit 4.
    - A population of 216,800 by 2031 which represents an increase of 16.0% as compared to the population of 186,948 in May 2021, as identified in

[9] https://www.oeb.ca/sites/default/files/Letter%20from%20the%20Minister%20of%20Energy%20and%20Electrification%20-%202024-1074.pdf
[10] https://www.oeb.ca/consultations-and-projects/policy-initiatives-and-consultations
[11] Appendix K, BHI's DSP, 2026 Cost of Service Application

Table 10 below.[12] This is a significant change as compared to BHI's 2021 Cost of Service application for which population growth since 2016 was 2.0%.

Table 10 - City of Burlington Population Growth

Year	Population	Growth
2016	183,314	
2021	186,948	2.0%
2031	216,800	16.0%
2051	265,000	22.2%

The importance of, and public focus on, sustainability, resilience, and reliability, especially in light of climate change, increases the pressure on BHI to meet future demands. BHI must ensure it has the capacity to innovate while maintaining and hardening its grid. An inadequate complement of staff could lead to delays in grid modernization, service interruptions, and an inability to meet regulatory requirements and government net-zero targets. These challenges are compounded by increasing work demands, driven in part by anticipated housing growth, and the need to maintain and replace aging distribution infrastructure.

The above factors are driving an increase in headcount from 112 FTE in 2021 to 123 FTE in the 2026 Test Year, and a corresponding increase in associated salaries and benefits. These factors are discussed in further detail in Sections 4.1.2 and 4.3.1 of Exhibit 4 in this Application.

1.2.4 D.2.2 Operational Costs

Increases due to changes in operations account for $1,695,096 of the $8,912,701 increase in OM&A from the 2021 Actuals to the 2026 Test Year (exclusive of any changes to salaries and benefits), as identified in Table 8 above. The primary drivers of the increase in operational costs are:

- **Vegetation Management:** BHI’s vegetation management program is required to ensure the safe and reliable distribution of electricity. The primary drivers of the increase in vegetation management costs are an increase in the fixed price costs for scheduled vegetation management services, and additional tree trimming for customers and emergency vegetation management primarily due to increasing extreme weather in

[12] 23-516-CM-Burlingtons-Plan-From-Vision-to-Focus_FINAL_WEB.pdf

BHI's service territory. BHI discusses its vegetation management program in detail in Section 4.3.0.7 of Exhibit 4.

- **Asset Inspection, Testing & Scheduled Maintenance:** These activities are increasing due to changes to BHI's pole testing program which involves testing poles every three years instead of the practice of testing poles every seven years which was in place at the time of BHI's 2021 Cost of Service application; and the introduction of a maintenance program for Scada-Mate switches. Asset Inspection, Testing & Scheduled Maintenance programs were changed or introduced, as applicable, to identify at-risk assets; mitigate failure risk in order to defer more expensive capital replacements; reduce the frequency of customer outages; and improve reliability which has been declining as identified in Figure 1 in Section 1.2.6 C of this Exhibit 1. BHI discusses its Asset Inspection, Testing & Scheduled Maintenance program in detail in Sections 4.3.0.7 and 4.3.0.8 of Exhibit 4.

- **Provision of Locates** - The primary driver of the increase is driven by the volume of locates. Locate volumes are directly proportional to non-discretionary System Access projects outside of BHI's control, such as residential and commercial developments and renovations, and road widening projects, which have increased since 2021 as identified in Appendix 2-AA in the DSP. Locates are discussed in further detail in Section 4.3.0.7 of Exhibit 4.

- **Training** - The increase in training is due to an increase in both headcount and training requirements since 2021. Rising turnover rates and a growing focus on retention and development require additional resources to be allocated to training. An increasing focus on cyber security and artificial intelligence has necessitated additional training and development to that end.

1.2.4 D.2.3 Policy/Business Costs

Increases in policy/business costs account for $1,314,464 of the $8,912,701 increase in OM&A from the 2021 Actuals to the 2026 Test Year (exclusive of any changes to salaries and benefits), as identified in Table 8 above. The primary drivers of the increase in operational costs are:

- **Insurance** - BHI and the industry are experiencing a hard insurance market which is characterized by an upswing in the insurance market cycle when premiums increase, coverage terms are restricted, and capacity for most types of insurance decreases. This commenced in 2022 and continues. Pressures on reinsurance markets have meant both higher pricing and less reinsurance for BHI's insurer than desired, which has also driven up premiums. In addition, BHI increased its Commercial General Liability insurance in 2025 to mitigate risk associated with large construction projects such as road widening and electrification projects, and conducting work on third party owned lands. Insurance is discussed in further detail in Section 4.3.0.2 of Exhibit 4.

- **OEB Regulatory Costs -** The OEB's Annual Assessment costs and to a lesser extent, the costs associated with Cost Awards, account for the increase from the 2021 Actuals. OEB Regulatory Costs are discussed in further detail in Section 4.1.2.3 of Exhibit 4.

- **Consulting Fees** - BHI leverages consultants to provide expertise not available in-house, and to alleviate resourcing constraints. The primary driver of the increase in these costs is due to an increase in consulting services for (i) Engineering fees associated with design services for non-capital projects which have increased since 2021; and (ii) Regulatory and Accounting fees associated with an integrated reporting platform which automates financial statement reporting and rate application filings.

- **Postage/Mail Service/Stationery Costs -** Inflation is the primary driver of this increase. Canada Post mailing costs increased approximately 26% effective January 2025 to better align stamp prices with the rising cost of providing letter mail service to all Canadians. This cost increase is outside of BHI's control but was mitigated by transitioning some of its customers from paper bills to e-billing. The number of customers on e-billing increased from approximately 40% in 2021 to over 45% in 2024. More details are provided in Section 4.3.0.6 of Exhibit 4.

- **Subscriptions/Memberships** - BHI has several subscriptions and memberships to facilitate management of the business. The main reason for the increase from the 2021 Actuals to the 2026 Test Year is a new subscription which provides BHI access to research, education, and advice not available in-house, to assist it with the execution of its enterprise-wide IT/OT strategy and operating model. This is discussed in further detail in Section 4.3.0.12 of Exhibit 4.

- **Professional Fees** - Increases are primarily a result of new cyber security audit requirements mandated by the OEB as part of the OCSF which are outside of BHI's control; and an increase in financial audit and tax fees.

1.2.4 D.2.4 Technology Costs

Increases in technology costs account for $849,264 of the $8,912,701 increase in OM&A from the 2021 Actuals to the 2026 Test Year (exclusive of any changes to salaries and benefits), as identified in Table 8 above. The primary drivers of the increase in technology costs are as follows, with additional details provided in Section 4.3.0.12 of Exhibit 4 in this Application.

- **Software Licensing, Support and Maintenance** - These costs include licensing, support and maintenance for BHI's enterprise software applications. Costs have increased significantly due to (i) recurring fees associated with subscription based models (recorded as operating expenses) which have transitioned from traditional, one-time software license purchases (recorded as capital expenditures); (ii) the requirement for specialized cyber security software to mitigate the growing risk of cyber attacks; (iii) an overall increase in vendor support and maintenance costs associated with the lifecycle of BHI's software applications; and (iv) the introduction of new technology applications such as engineering design and estimating software, accounts payable software to automate invoice coding and payment processing, and support and maintenance associated with BHI's new OMS.

- **Technology Consulting Services** - These costs have increased since 2021, primarily due to an increase in costs to support BHI's CIS and Customer Portal which is outsourced to third parties. BHI's CIS is critical to (i) facilitate the issuance of timely and accurate bills to customers, process payments and manage billing cycles, (ii) store and manage customer data and processes service requests (e.g. new connections, disconnections and repairs); and (iii) interface with smart meters and collectors to collect and process consumption data to calculate usage, verify billing accuracy and offer usage insights to customers.

- **Hosting Services** - These costs are associated with third party services used to host BHI's business applications such as public websites, CIS solutions, Smart Metering solutions, financial transactions applications, cloud based file storage solutions, outage management systems and DNS hosting solutions. The increase is primarily driven by new solutions and applications implemented since 2021, in particular the implementation of the OEB-mandated Green Button and BHI's new Customer Account Portal which is hosted by a third party.

1.2.4 E Cost of Capital

BHI summarizes its proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital ("WACC") in Table 11 below.

Table 11 – Proposed Capital Structure and Cost of Capital Parameters

Description	Capital Structure	Rate of Return
Short Term Debt	4.0%	3.91%
Long Term Debt	56.0%	4.36%
Equity	40.0%	9.00%
Weighted Average Cost of Capital		**6.20%**

BHI is using the OEB's cost of capital methodology for its capital components. BHI's proposed deemed capital structure for the 2026 Test Year is 60% debt (56.0% long-term debt and 4.0% short-term debt) and 40.0% equity. BHI is using the OEB's cost of capital parameters as published on March 27, 2025[13], subject to an update if new parameters are available prior to the OEB rendering its Decision on this Application. The long term debt rate of 4.36% for the 2026 Test Year used in this Application is the weighted average of the interest on BHI's outstanding long-term debt instruments and forecasted new debt in the 2026 Test Year. This approach is in compliance with the OEB Staff Report *Review of the Cost of Capital for Ontario's Regulated Utilities*[14], issued January 14, 2016.

[13] https://www.oeb.ca/industry/rules-codes-and-requirements/cost-capital-parameter-updates

[14] EB-2009-0084, Table 1: Current Cost of Capital Methodology, p 3

1.2.4 F Cost Allocation and Rate Design

BHI engaged Power Advisory LLC ("Power Advisory") to assist in completing a Cost Allocation Study for the 2026 Test Year using the OEB-approved cost allocation model. BHI did not deviate from the OEB's cost allocation and rate design methodologies.

BHI has made the following changes to its cost allocation since its 2021 Cost of Service application as follows:

- **Weather Normalization Methodology:** The methodology used in BHI's last Cost of Service application has been refined to account for differences in weekday and weekend/holiday demands. The demand data used in the 2026 cost allocation model is based on an average of three years of weather-normalized demands scaled to test year consumption. In the 2021 Cost of Service application, demand data was based on a single year of weather-normalized demands scaled to the test year.
- **Transformer Ownership Allowance:** The treatment of the Transformer Ownership Allowance has been revised in the current version of the cost allocation model, as compared to the version that BHI used in its previous rebasing application. BHI confirms that it is using the OEB's 2025 Cost Allocation Model – Version 1.0 which incorporates the current treatment of the Transformer Ownership Allowance.

BHI provides a comparison of its proposed Revenue to Cost ("R-C") ratios in this Application to R-C ratios approved in BHI's 2021 Cost of Service application in Table 12 below.

Table 12 – Revenue to Cost Ratios Comparison

Rate Class	Revenue to Cost Ratios			
	2021 Cost of Service	Status Quo	2026 Test Tear	Policy Range
Residential	98.75%	100.90%	100.90%	85-115%
GS < 50 kW	118.51%	108.48%	108.48%	80-120%
GS > 50 kW	94.42%	91.83%	92.25%	80-120%
Street Lighting	120.00%	126.47%	120.00%	80-120%
Unmetered Scattered Load (USL)	120.00%	149.98%	120.00%	80-120%

BHI's calculations in the Cost Allocation Model result in the R-C Ratios for the Street Lighting Class and USL being above the OEB-approved ceiling of 120%. BHI adjusted the revenue for these classes to decrease the R-C Ratios to 120% in the 2026 Test Year. This resulted in a shortfall in proposed revenue collected of ($51,402), which BHI allocated to the GS>50 kW rate class, which was the only rate class with a R-C Ratio of less than 100%. BHI is not proposing to continue to rebalance rates after the 2026 Test Year.

BHI provides a comparison of its proposed fixed/variable splits in this Application to the fixed/variable splits approved in BHI's 2021 Cost of Service application in Table 13 below. There are no significant changes from the 2021 Cost of Service application.

Table 13 – Fixed/Variable Split Comparison

Rate Class	Fixed Revenue Proportion			Variable Revenue Proportion		
	2021 OEB-Approved	2025 Bridge Year	2026 Test Year	2021 OEB-Approved	2025 Bridge Year	2026 Test Year
Residential	100.00%	100.00%	100.00%	—%	—%	—%
GS < 50 kW	42.73%	38.56%	38.56%	57.27%	61.44%	61.44%
GS > 50 kW	9.81%	10.59%	9.08%	90.19%	89.41%	90.92%
Street Lighting	64.86%	64.96%	64.96%	35.14%	35.04%	35.04%
Unmetered Scattered Load (USL)	55.23%	54.85%	54.85%	44.77%	45.15%	45.15%

BHI is not proposing a rate mitigation plan in this Application as there are no rate classes for which the total bill impact exceeds the 10% total bill impact threshold.

1.2.4 G Deferral and Variance Accounts

BHI is proposing to dispose of $6,173,254 in its Group 1 and Group 2 Deferral and Variance accounts (“DVAs”) as identified in Table 14 below. The amount allocated to Regulated Price Plan (“RPP”) and non-RPP customers is also identified. BHI is proposing a disposition period of one year for its Group 1 and Group 2 accounts.

Table 14 – DVA Disposition

Deferral and Variance Accounts	USoA	Total Proposed for Disposition	RPP Customers	non-RPP Customers
Group 1				
Smart Metering Entity Charge Variance Account	1551	$(55,993)	$(55,190)	$(803)
RSVA - Wholesale Market Service Charge	1580	$(423,745)	$(228,023)	$(195,722)
Variance WMS – Sub-account CBR Class B	1580	$661,564	$0	$661,564
RSVA - Retail Transmission Network Charge	1584	$301,641	$162,317	$139,323
RSVA - Retail Transmission Connection Charge	1586	$(274,469)	$(147,696)	$(126,773)
RSVA - Power (excluding Global Adjustment)	1588	$722,864	$388,983	$333,880
RSVA - Global Adjustment	1589	$3,026,767	$0	$3,026,767
Total Group 1 Balances		**$3,958,628**	**$120,391**	**$3,838,237**
Group 2				
Pole Attachment Revenue Variance	1508	$283,642	$222,327	$61,315
Customer Choice Initiative Costs	1508	$158,757	$85,429	$73,328
Green Button Initiative Costs	1508	$260,320	$140,082	$120,238
Capital Additions Dundas Street Road Widening Project	1508	$(15,264)	$(8,214)	$(7,050)
Capital Additions Waterdown Rd Road Widening Project	1508	$(6,032)	$(3,246)	$(2,786)
Collection Charge Lost Revenue	1508	$835,348	$449,513	$385,835
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	$(77,656)	$(41,788)	$(35,868)
Extra-Ordinary Event Costs - 2022 Wind Storm (z-factor)	1572	$4,749	$2,556	$2,194
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	$450,322	$242,325	$207,997
Impacts Arising from the COVID-19 Emergency	1509	$320,439	$251,169	$69,270
Total Group 2 Balances		**$2,214,625**	**$1,340,153**	**$874,472**
Total DVA Balances		**$6,173,254**	**$1,460,544**	**$4,712,709**

Table 15 and Table 16 below provide a breakdown of the Group 1 and Group 2 balances and associated rate riders by rate class.

Table 15 – Group 1 Balances and Proposed Rate Riders by Rate Class

Rate Class	Group 1 DVA Rate Rider			
	Unit	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/ Variance Accounts
RESIDENTIAL	kWh	554,448,693	$72,275	$0.0001
GENERAL SERVICE LESS THAN 50 kW	kWh	168,539,128	$32,823	$0.0002
GENERAL SERVICE 50 TO 4,999 kW	kW	1,968,903	$163,211	$0.0829
UNMETERED SCATTERED LOAD	kWh	3,312,078	$738	$0.0002
STREET LIGHTING	kW	15,672	$1,250	$0.0797
TOTAL			**$270,297**	

Rate Class	CBR Rate Rider			
	Unit	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
RESIDENTIAL	kWh	554,448,693	$283,349	$0.0005
GENERAL SERVICE LESS THAN 50 kW	kWh	168,539,128	$86,131	$0.0005
GENERAL SERVICE 50 TO 4,999 kW	kW	1,508,448	$272,465	$0.1806
UNMETERED SCATTERED LOAD	kWh	3,312,078	$1,693	$0.0005
STREET LIGHTING	kW	15,672	$2,866	$0.1829
TOTAL			**$646,504**	

Rate Class	GA Rate Rider			
	Unit	kW / kWh / # of Customers	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	3,367,431	$20,787	$0.0062
GENERAL SERVICE LESS THAN 50 kW	kWh	17,512,138	$108,101	$0.0062
GENERAL SERVICE 50 TO 4,999 kW	kWh	450,606,783	$2,781,569	$0.0062
UNMETERED SCATTERED LOAD	kWh	—	$0	n/a
STREET LIGHTING	kWh	5,551,543	$34,269	$0.0062
TOTAL			**$2,944,727**	

Table 16 – Group 2 Balances and Proposed Rate Riders by Rate Class

Rate Class	Group 2 DVA Rate Rider			
	Unit	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL	# of Customers	63,119	$790,644	$1.04
GENERAL SERVICE LESS THAN 50 kW	kWh	168,539,128	$224,185	$0.0013
GENERAL SERVICE 50 TO 4,999 kW	kW	1,968,903	$867,307	$0.4405
UNMETERED SCATTERED LOAD	kWh	3,312,078	$4,439	$0.0013
STREET LIGHTING	kW	15,672	$7,611	$0.4857
TOTAL			**$1,894,187**	
Rate Class	**Account 1509 Rate Rider**			
	Unit	**kW / kWh / # of Customers**	**Allocated Group 2 Balance**	**Rate Rider for Group 2 Accounts**
RESIDENTIAL	# of Customers	63,119	$204,331	$0.27
GENERAL SERVICE LESS THAN 50 kW	# of Customers	5,823	$43,864	$0.6277
GENERAL SERVICE 50 TO 4,999 kW	# of Customers	952	$69,712	$6.1022
UNMETERED SCATTERED LOAD	# of Customers	584	$900	$0.1285
STREET LIGHTING	# of Customers	17,348	$1,631	$0.0078
TOTAL			**$320,439**	

BHI is not requesting to establish any new DVAs. BHI is requesting discontinuation of the DVAs identified in Table 17 below. The rationale for these proposals and further details on BHI's DVAs are provided in Exhibit 9 of this Application.

Table 17 – Proposed List of DVAs to be Discontinued

Group 2 Account	USoA
Green Button Initiative Costs	1508
Capital Additions Dundas Street Road Widening Project	1508
Capital Additions Waterdown Rd Road Widening Project	1508
Collection Charge Lost Revenue	1508
Extra-Ordinary Event Costs - 2022 Wind Storm (z-factor)	1572
Impacts Arising from the COVID-19 Emergency	1509

1.2.4 H. Bill Impacts

BHI provides a summary of the bill impacts for typical customers in all customer classes in Table 18 below.

The bill impacts to be used for the notice of application are provided as Sub-Total A which represents the bill impacts that result only from the distribution costs changes.

Table 18 – Summary of Bill Impacts

Class	kWh	kW	Distribution (Fixed and Volumetric) Sub-Total A			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$32.74	$42.58	$9.84	30.1 %
GS<50 kW	1,500		$58.48	$76.29	$17.81	30.5 %
GS<50 kW	2,000		$68.18	$89.19	$21.01	30.8 %
GS>50 kW	36,700	200	$851.96	$1,168.36	$316.40	37.1 %
Street Lighting	175	0.22	$1.68	$2.13	$0.45	26.7 %
Unmetered Scattered Load	2,000		$48.64	$51.09	$2.45	5.0 %
Class	kWh	kW	Distribution (including pass-through) Sub-Total B			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$36.67	$46.44	$9.77	26.6 %
GS<50 kW	1,500		$66.22	$83.73	$17.51	26.4 %
GS<50 kW	2,000		$78.37	$98.98	$20.61	26.3 %
GS>50 kW	36,700	200	$983.45	$1,462.84	$479.39	48.7 %
Street Lighting	175	0.22	$2.70	$3.99	$1.29	47.8 %
Unmetered Scattered Load	2,000		$41.17	$36.95	$(4.22)	(10.3)%
Class	kWh	kW	Total Bill (after HST and OER)			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$133.18	$142.94	$9.76	7.3 %
GS<50 kW	1,500		$256.83	$274.32	$17.49	6.8 %
GS<50 kW	2,000		$332.43	$353.02	$20.59	6.2 %
GS>50 kW	36,700	200	$5,870.47	$6,412.18	$541.71	9.2 %
Street Lighting	175	0.22	$26.82	$28.28	$1.46	5.4 %
Unmetered Scattered Load	2,000		$312.49	$314.53	$2.05	0.7 %

1.2.5 Materiality Threshold

Section 2.0.8 – Materiality Thresholds of the Chapter 2 Filing Requirements states that the materiality threshold relates to the revenue requirement impact of the expenditure. BHI's applicable materiality threshold is defined as 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. BHI's distribution service revenue requirement for 2026 in this Application is $48,485,131 which equates to a materiality threshold of $242,000. BHI provides its materiality threshold for various components of its Application in Table 19 below. In appropriate circumstances, BHI's variance analysis also discusses certain OM&A variances below the threshold.

Table 19 – Materiality Threshold

Description	2026 Test Year
Proposed Distribution Revenue Requirement	$48,485,131
0.5% of Proposed Distribution Revenue Requirement	$242,426
Revenue Requirement Impact for Materiality Threshold	**$242,000**

Description	Rate Base	WCA (COP and OM&A)	Capital Expenditures	Revenues	OM&A and Depreciation	PILS
Materiality Threshold	$6,700,000	$52,000,000	$3,000,000	$242,000	$242,000	$329,252
Revenue Requirement Impact	$242,000					

1.3 ADMINISTRATION

In accordance with the Ontario Energy Board's ("OEB's") *Filing Requirements for Electricity Distribution Rate Applications – 2025 Edition for 2026 Rate Applications – Chapter 2 Cost of Service*, dated December 9, 2024, ("the Chapter 2 Filing Requirements"), this section provides information relating to the administration of this Application.

1.3.1 Certification of Evidence

BHI provides certification of the evidence, attached as Appendix D to this Exhibit 1.

1.3.2 Board of Directors Certification

BHI provides a letter from its Board of Directors certifying that it is aware of and approves the submission of the Application, attached as Appendix E to this Exhibit 1.

1.3.3 Primary Contact Information

Adam Pappas
Director of Regulatory, Supply Chain & Capital Planning
Burlington Hydro Inc.
1340 Brant Street
Burlington, Ontario L7R 3Z7
Telephone: (905) 332-2341
Fax: (905) 336-4399
Email: apappas@burlingtonhydro.com

1.3.4 Legal Representation

Charles Keizer
Partner
Torys LLP
79 Wellington Street West #3300
Toronto, Ontario M5K 1N2
Email: ckeizer@torys.com

1.3.5 Internet Address and Media Accounts

BHI's main webpage is the following: www.burlingtonhydro.com.

All evidence and Cost of Service Application documents will be available in the Regulatory Affairs section of BHI's website:

https://www.burlingtonhydro.com/about/regulatory-affairs.html

The social media accounts maintained by BHI are as follows:

- X https://X.com/BurlingtonHydro
- LinkedIn https://www.linkedin.com/company/burlington-hydro-inc-
- YouTube https://www.youtube.com/user/burlingtonhydro
- Instagram https://www.instagram.com/burlingtonhydro
- Facebook https://www.facebook.com/burlingtonhydro

1.3.6 Publication and Notice

BHI will follow the OEB's instructions regarding the Publication of Notice in relation to this Application. BHI proposes to publish the Notice of Application in *Inside Halton*, a free online publication, and to BHI's website at: http://www.burlingtonhydro.com.

1.3.7 Form of Hearing

BHI requests that this Application be disposed of by way of a written hearing. It is BHI's view that this would be the most efficient means to reach a Decision.

1.3.8 Requested Effective Date

BHI is requesting approval of the proposed distribution rates and other charges set out in this Application effective January 1, 2026.

BHI requests that its current (i.e. 2025) rates provided in Appendix B of Exhibit 8 be declared interim effective January 1, 2026, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2026; and that it be permitted to establish an account to recover any differences between the interim rates and the actual rates effective January 1, 2026 based on the OEB's Decision and Order.

1.3.9 Changes to Methodologies used in Previous Applications

There have been no changes to methodologies since BHI's 2021 Cost of Service application.

1.3.10 OEB Directions from Previous Decisions and/or Orders

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

1.3.10.1 Distribution Losses Plan Submission

As part of the approved Settlement Agreement in its 2021 Cost of Service application[15], BHI committed to:

- Make best efforts to target its five-year average total system losses at the target of 3.4% through cost-effective measures subject to variation in distribution losses due to factors outside of BHI's control;
- Prepare a plan to reduce distribution losses as much as possible through cost-effective measures and file with the OEB when completed;
- Implement as many of the cost-effective measures set out in its plan as possible during 2022-2025; and
- Incorporate the remaining cost-effective measures to mitigate losses into its next rebasing application and DSP.

BHI prepared a Distribution System Loss Analysis and filed it with the OEB through a letter dated August 17, 2023, attached as Appendix C to Exhibit 8. Between 2022 and 2024, BHI undertook various cost-effective initiatives recommended in the Distribution System Loss Analysis to minimize distribution losses while ensuring system reliability and performance. Examples of measures taken and projects completed are as follows:

- Load Balancing and System Optimization – Adjustments based on asset size and demand to optimize efficiency at Appleby MS (F1, F4, F5, F6), Brant MS (F2, F3), Howard MS (F1, F2), and Palermo TS (A4M5, A4M6).
- Distribution Feeder Reconfiguration – Modifications to feeder configurations to improve system efficiency at Cumberland TS (76M25, 76M26), Burlington TS (39M5, 39M35).
- Voltage Conversion – Upgrading older 4.16kV and 13.8kV networks to the modern 27.6kV standard to reduce losses. Examples of projects completed include Fairview MS (F2, F3).

[15] EB-2020-0007, Decision and Rate Order, Schedule B

The above measures and projects contributed to loss reduction to the respective assets, and average total system losses decreased from 1.0438 in 2021 to 1.0423 in 2024. For further details, please refer to Section 8.8.1 in Exhibit 8.

BHI plans to continue implementing cost-effective loss reduction measures over the 2026-2030 period. It will conduct regular power system analyses, including system loss estimation using CYME software, and take corrective actions as needed. BHI's strategy for the 2026-2030 period will focus on load balancing, system optimization, distribution feeder reconfiguration, and voltage conversion as part of broader system investments. BHI does not undertake projects solely for loss reduction, but instead incorporates these measures into broader system improvement plans that consider asset age, load balancing, feeder congestion, and other operational priorities.

1.3.10.2 Tracking of New Metrics

As part of the approved Settlement Agreement in its 2021 Cost of Service application[16], BHI committed to:

- track two new reliability metrics;
- track three new unit cost metrics; and
- separately track proactive and reactive asset replacements (quantity and total expenditures) for identified asset classes.

1.3.10.2.1 Reliability and Unit Cost Metrics

The new reliability metrics (with specific performance targets for the 2021-2025 period) and unit cost metrics were identified in Table 1.1D of BHI's Settlement Proposal[17], and are reproduced in Figure 4 below.

[16] EB-2020-0007, Decision and Rate Order, Schedule B
[17] EB-2020-0007, Settlement Proposal, p13

Figure 4 - Additional Reliability Metrics (from 2021 Cost of Service)

Performance Outcome	Measure	Metric	2021-2023 Target	2024-2025 Target
Cost Efficiency and Effectiveness	DSP Implementation Progress	SAIDI (Ex MEDs) caused by Defective Equipment	Previous 5-year rolling average	5% reduction vs. previous 5-year rolling average
		SAIFI (Ex MEDs) caused by Defective Equipment	Previous 5-year rolling average	5% reduction vs. previous 5-year rolling average
	Cost Metrics	Unit Cost: Wood Pole replacement ($/pole)	Monitor	
		Unit Cost: UG Primary Cable Rebuild ($/km)	Monitor	
		Unit Cost: Station Primary Switchgear replacement ($/unit)	Monitor	

BHI experienced a deteriorating trend in the reliability metrics related to defective equipment from 2021 to 2024, as identified in Table 5.2-2 of the DSP and in Figure 2 of this Exhibit 1. Further details are provided in Section 5.2.3.1.1 of the DSP.

BHI's unit cost metrics for wood pole replacements, underground primary cable rebuilds and station primary switchgear replacements are identified in Table 5.2-4 of the DSP. Further details are provided in Section 5.2.3.1.4 of the DSP.

1.3.10.2.2 Tracking of Proactive versus Reactive Asset Replacement

BHI tracked reactive versus proactive capital expenditures separately across specific programs and projects, as identified in Table 1.1C of BHI's Settlement Proposal[18], and reproduced in Figure 5 below. BHI tracked the quantity (e.g., the number of wood poles replaced) and the total expenditures for both proactive and reactive asset replacements.

Figure 5 - Proactive vs. Reactive Replacement Tracking (from 2021 Cost of Service)

System Renewal Program
Pole Replacement
Underground Rebuilds
Switchgear Replacement
Station Transformer Replacement
MS Feeders Cable Replacement
Distribution Transformer Replacement
Switch Replacement

[18] Ibid

BHI's expenditures for proactive and reactive replacements for the categories identified in Figure 5 above are identified in Table 5.2-3 of the DSP and discussed further in Section 5.2.3.1.1 of the same.

1.3.10.3 Accounting Order - Asymmetrical Capital Variance Accounts

As part of the approved Settlement Agreement in its 2021 Cost of Service application[19], the Parties agreed to establish two separate asymmetrical capital variance accounts to track the revenue requirement associated with the difference between the budgeted and actual net capital additions in the 2021 Test Year and the resulting impact through the IRM period for the Dundas Street Road Widening Project and the Waterdown Rd Road Widening Project.

As per the approved Accounting Order[20], BHI was to establish two sub accounts; i) Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account (“CVA1”), and ii) Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account (“CVA2”), to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the above projects and the resulting impact during the IRM period. If the revenue requirement impact was lower than forecast in the 2021 Test Year, (budgeted net capital additions in the 2021 Test Year exceed actual net capital additions), BHI would make a credit entry in the applicable variance account representing a refund to ratepayers. As an asymmetrical account, if the revenue requirement impact was higher than forecast in the 2021 Test Year, (actual capital additions in the 2021 Test Year exceed budgeted capital additions), no entry would be made to the variance account. The variance accounts were to be disposed of at BHI’s next rebasing application, if applicable, as per the OEB’s guidelines related to Group 2 Accounts.

1.3.10.3.1 Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project

In accordance with the approved Accounting Order[21], BHI established a new variance account effective May 1, 2021 (CVA1) to record the revenue requirement associated with the difference

[19] EB-2020-0007, Decision and Rate Order, Schedule B
[20] EB-2020-0007, Decision and Rate Order, Schedule B, Appendix B
[21] EB-2020-0007, Decision and Rate Order, Schedule B, Appendix B

between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Dundas Street Road Widening Project and the resulting impact during the IRM period.

Actual net capital additions on the Dundas St Road Widening project were $(2,518,633) less than forecast in 2021, and BHI made credit entries over the 2021-2025 period reflecting the resulting impact through the IRM period.

BHI also made principal and interest entries to this account in 2025 as a result of the decision on BHI's 2025 IRM Rate Application, where the OEB approved ICM funding for a different road widening project along Dundas Street ("2025 Dundas Road Widening Project")[22].

Further details on the entries to, and disposition of, this account are provided in Section 9.1.11 of Exhibit 9 in this Application.

1.3.10.3.2 Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project

In accordance with the approved Accounting Order[23], BHI established a new variance account effective May 1, 2021 (CVA2) to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Waterdown Rd Road Widening Project and the resulting impact during the IRM period.

Actual net capital additions on the Waterdown Rd Road Widening project were $(365,852) lower than budget in 2021, and BHI made credit entries over the 2021-2025 period reflecting the resulting impact through the IRM period.

Further details on this account are provided in Section 9.1.12 of Exhibit 9 in this Application.

[22] EB-2024-0010, Decision and Order, December 17, 2024

[23] EB-2020-0007, Decision and Rate Order, Schedule B, Appendix B

1.3.11 Conditions of Service

BHI confirms that there are no changes to its Conditions of Service as a result of this Application. The current version of its Conditions of Service is available on its website: https://burlingtonhydro.com/conditions-of-service.html.

BHI updated its Conditions of Service effective January 1, 2024. Figure 6 provides a summary of the key changes to its Conditions of Service compared to the version that was referenced in its 2021 Cost of Service application.

Figure 6 - Changes to BHI's Conditions of Service

Section	Section Title	Summary of Change
1.6	Customer Rights and Obligations	Removed redundant sections contained elsewhere in the Conditions of Service and/or in the Distribution System Code (“DSC”), Retail Settlement Code (“RSC”), Standard Supply Service Code (“SSSC”) or the Electricity Act.
1.6.1	Right to Electricity	Revised language to clarify Customers’ rights to electricity.
1.6.6	Trees and Vegetation Management	Revised language to clarify requirements for customers and their contractors when completing vegetation management near BHI lines.
1.7.1	Space and Access	Added language to include specific guidance on transformer space and access.
1.7.3	Customer Requested Disconnection	Revised language to clarify requirements for customer equipment upgrades or changes.
1.7.6	Underground Cable Locating	Added language to clarify requirements when exposing BHI owned cables.
1.7.7	Planned Interruptions	Added language to provide guidance to Customers requiring a higher degree of secure supply than that of normal supply.
1.7.8	Defective Customer Equipment	Added language to clarify BHI rights and Customer responsibilities regarding Customer-owned equipment that may affect the integrity or reliability of BHI’s distribution system.
1.8	Disputes	Removed redundant sections contained elsewhere in the Conditions of Service; revised language to be consistent with section 10 of the DSC (Consumer Complaint Response Process).
2.1	Connections	Added language to clarify the connection process including estimated timelines, Customer requirements, and conditions that must be met in order for BHI to connect the Customer.
2.1.1	Building That Lies Along	Revised language to clarify the Basic Connection as well as variable connection charges customers may be subject to.
2.1.2	Expansions / Offer to Connect	Revised language to clarify the process followed to determine any required capital contributions and/or expansion deposits; added language regarding cost responsibility for dedicated supplies or multiple redundant supplies.
2.1.5	Relocation of Plant	Added language to clarify cost responsibility for relocation of BHI plant.
2.1.7.6	Assignment and Succession	Added language to clarify that refunds/returns of bonds, deposits or capital contributions will be released to the executor of the agreement.
2.2.1	Disconnection	Revised language to be consistent with new Customer Service Rules that came into effect March 1, 2020; removed reference to collection charges for unpaid accounts; added language to clarify Customer’s responsibilities regarding plans to demolish any buildings that house BHI’s distribution equipment.

Section	Section Title	Summary of Change
2.2.2	Reconnection	Added language to clarify that after disconnection for six months, the service will be treated as a new service.
2.3.1	Limitations on the Guarantee of Supply	Revised language to clarify BHI's right to interrupt customer supply at any time and during any season to maintain, upgrade and improve its system; removed past practice of maintaining a database of customers with critical medical conditions.
2.3.4	Standard Voltage Offerings	Added language to clarify BHI's service voltage offerings.
2.3.6	Back-up Generators	Added language to clarify BHI's rights when a Customer's backup generator will not safely interface with BHI's distribution system.
2.3.7	Metering General	Added reference to BHI's Metering Standards document, including how to obtain a copy.
2.3.7.1	Location of Metering	Added language to clarify meter room requirements for general commercial and industrial (bulk- or multi-metered) services.
2.3.7.3	Metering Equipment / Current Transformer Enclosure	Added language to clarify requirements related to metering equipment and current transformer enclosures.
2.3.7.5	Meter Reading	Added language to clarify the Customer's responsibility to ensure the meter is in a location to allow wireless communication using standard infrastructure, and to facilitate the installation of this infrastructure.
2.3.7.6	Final Meter Reading	Revised language to clarify requirement for Customer to provide 5 business days notice for final meter reading where service is no longer required, or the Customer is switching to a competitive retailer.
2.3.7.8	Meter Dispute Testing	Revised language to clarify meter dispute process.
2.4.3	Deposits	Revised language to be consistent with new Customer Service Rules that came into effect March 1, 2020 (DSC 2.4.9 A and B); good payment history changed from 5 years to 3 years for General Service customers; added language that security deposits will be waived for new residential customers enrolling in an equal payment plan and/or a pre-authorized payment plan.
2.4.4	Billing	Changed "equal billing plan" to "equal payment plan" per amendments to the SSSC; removed redundant sections contained elsewhere in the Conditions of Service and/or in the DSC, SSC, RSC or the Electricity Act.
2.4.5.1	Payment Options	Changed "equal billing plan" to "equal payment plan" per amendments to the SSSC; revised language to clarify that BHI will apply any payments received to the total outstanding balance of the electricity account.
2.4.5.2	Late Payment Charges	Updated minimum payment period to 20 days to be consistent with new Customer Service Rules that came into effect March 1, 2020 (DSC 2.6.3).
2.5	Customer Information	Added language to include reference to BHI's Privacy Policy and contact info for BHI's Privacy Officer.

Section	Section Title	Summary of Change
3.1.2	Temporary Services	Added language to clarify BHI's rights in case of overlap of temporary and permanent service.
3.2.1	Residential - Application	Added language to clarify that only one point of supply is allowed per municipal address, although multiple metered services may be connected; clarified that where a non-residential services exist on the same property the service entrance will be treated as a General Service of the characteristics consistent with the entire site, not as a Residential service.
3.2.3	Residential - Ownership and Operational Demarcation Point	Added language to clarify the Customer's responsibilities for civil infrastructure on their property.
3.3.3	General Service < 50kW - Ownership and Operational Demarcation Point	Added language to clarify the Customer's responsibilities for civil infrastructure on their property.
3.4.3	General Service > 50kW - Ownership and Operational Demarcation Point	Added language to clarify the Customer's responsibilities for civil infrastructure on their property.
3.3.6	Billing	Revised language to clarify that under exceptional circumstances BHI may bill Customers based on estimated consumption (previous language stated *no more than twice* in a 12-month period).
3.5	Embedded Generation and Energy Storage	Added language to clarify this section also applies to Customers with energy storage.
3.7.5	Unmetered Connections - Metering	Added language to clarify metering requirements.
3.7.8	Unmetered Connections - Motors	Revised language to clarify that Customers must consult with BHI regarding the installation of any motors on an unmetered connection.
3.8	Streetlighting	Added language to clarify that service to streetlights will be unmetered, and to clarify the method of billing.
4	Glossary of Terms	Added definitions to align with the changes.
5	Appendices	Added an appendix outlining BHI's specific requirements pertaining to the OEB's Electric Vehicle Charging Connection Procedures (EVCCP), as it relates to DSC requirements and its Conditions of Service.

1.3.12 Confirmation of Rates and Charges

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

1.3.13 Corporate and Utility Organizational Structure

BHI was incorporated and wholly transferred into the ownership of the City of Burlington on January 1, 2000, as a for-profit company. The City created a holding company, originally

Burlington Hydro Electric Inc. (“BHEI”), and since 2019, Burlington Enterprises Corporation (“BEC”), to oversee two subsidiary companies: a regulated “wires” company, Burlington Hydro Inc., and an unregulated company, Burlington Electricity Services Inc. ("BESI").

Figure 7 below identifies the corporate organizational structure of BEC, including Board of Directors representation for BEC, BHI, and BESI.

Figure 7 - BEC Corporate Organizational Structure

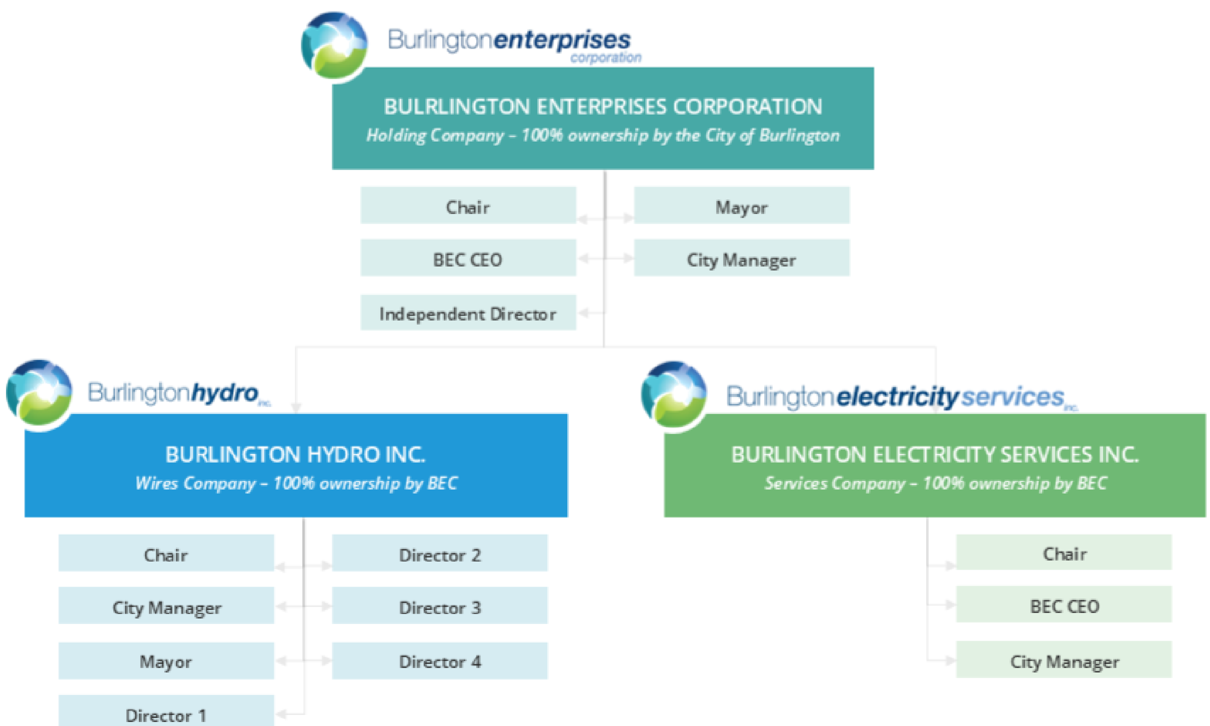
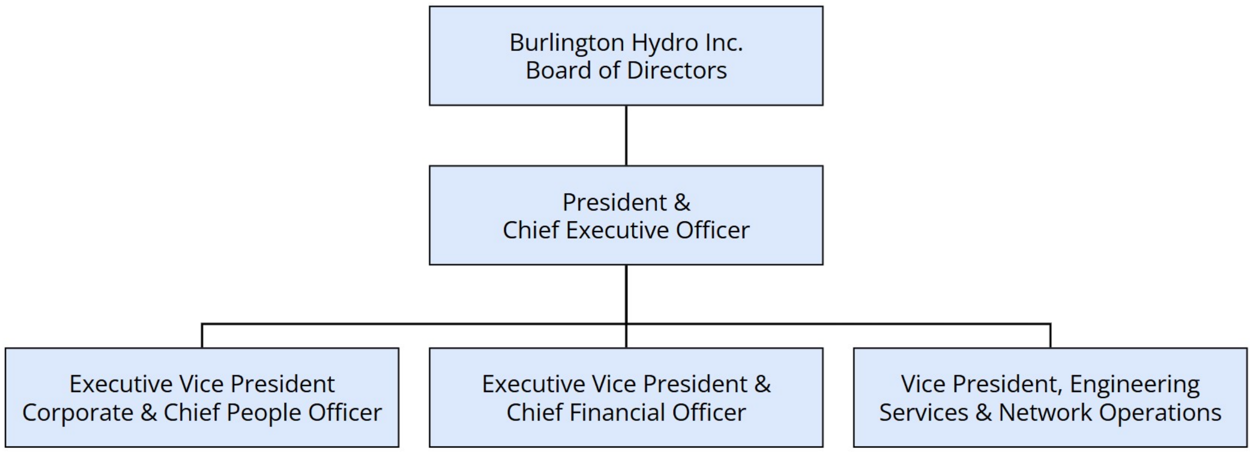


Figure 8 identifies the executive and senior management positions within the utility, and reporting relationship between the utility and parent company.

Figure 8 - BHI Corporate Structure



1.3.14 Specific Relief Requested

This Application is submitted pursuant to section 78 of the Ontario Energy Board Act, 1998. Herein, BHI is seeking the following specific approvals. The approvals sought in this Application are essential for BHI to meet its obligations while continuing to provide safe, reliable and efficient service to its customers.

1. Approval of the 2026 Test Year revenue requirement as proposed in Exhibit 6 – Revenue Requirement and Revenue Deficiency or Sufficiency as follows:
    a. Approval of the 2026 Test Year Service revenue requirement of $52,840,656;
    b. Approval of the 2026 Test Year Base revenue requirement of $48,485,131; and
    c. Approval of the 2026 Revenue offsets of $4,355,525;
2. Approval of 2026 distribution rates and charges, effective January 1, 2026, as proposed in Appendix C - Proposed Tariff of Rates and Charges of Exhibit 8;
3. Approval of BHI's DSP filed as Appendix A in Exhibit 2;
4. Approval for an Advanced Capital Module ("ACM") to replace the existing SCADA system and implement a fully integrated ADMS, as set out in Section 2.7 of Exhibit 2;
5. Approval of the inclusion into the 2026 opening rate base of distribution assets associated with the relocation of electrical infrastructure for the Dundas Street Road Widening project from Guelph Line to Kerns Road and from Northampton Boulevard to Guelph Line; as documented in Section 2.8 of Exhibit 2;
6. Approval of the 2026 load forecast as documented in Exhibit 3;

7. Approval of a revised loss factor as identified in Section 8.8 of Exhibit 8;
8. Approval of updated Retail Transmission Service Rates ("RTSRs"), as identified in Section 8.2 of Exhibit 8;
9. Approvals related to deferral and variance accounts, as set out in Exhibit 9: Deferral and Variance Accounts:
    a. Approval for the clearance of the balances recorded in certain Group 1 deferral and variance accounts of $3,958,629 on a final basis by means of class-specific rate riders and manual adjustments, effective January 1 to December 31, 2026, as identified in Section 9.1.0.1 of Exhibit 9;
    b. Approval for the clearance of the balances recorded in certain Group 2 deferral and variance accounts of $2,214,625 by means of class-specific rate riders and adjustments effective January 1 to December 31, 2026, as identified in Section 9.1.0.2 of Exhibit 9:
    c. Approval of the continuation of certain deferral and variance accounts, as set out in Section 9.0.1 of Exhibit 9;
    d. Approval of discontinuation of certain deferral and variance accounts, as set out in Section 9.0.1 of Exhibit 9
10. Approval to make its current (i.e., 2025) rates provided in Appendix B of Exhibit 8 interim effective January 1, 2026, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2026;
11. Approval to establish an account to recover any differences between the interim rates and the actual rates effective January 1, 2026 if the preceding approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2026; and
12. Approval of other items or amounts that may be requested by BHI in the course of the proceeding, and such other relief or entitlements that the OEB may grant.

1.4 DISTRIBUTION SYSTEM OVERVIEW

BHI is an LDC serving approximately 69,000 residential and commercial customers in the City. It operates under distribution licence [ED-2003-0004] and maintains 32 MSs and approximately 1,500 kilometers of distribution lines throughout its service area. The company is wholly owned by the City and the boundaries of the service area are:

- West:
    - Hwy. 6 (North Shore Blvd. to Old York Rd.)
    - Snake Rd. (Old York Rd. to Main St. S.)
    - Mountainbrow Rd. to Kerns Rd.
    - Kerns Rd. / Parkside Dr./ Millborough Townline (Mountainbrow Rd. to Derry Rd.)
- North:
    - Plains Rd. to Snake Rd. to Mountainbrow Rd. to King Rd. ending at Kerns Rd.
    - Derry Rd. (Millborough Townline to Bell School Line)
    - 1 Side Rd. (Bell School Line to Tremaine Rd.)
- East:
    - Bell School Line (Derry Rd. to 1 Side Rd.)
    - Tremaine Rd. / Burloak Dr. (1 Side Rd. to Lakeshore Rd.)
- South:
    - The shore of Lake Ontario

BHI's total service area is 188 square km, of which 90 square km are rural and the remainder is urban. Geographically, Burlington is located in Halton Region between the north shore of Lake Ontario and the Niagara Escarpment. Economically, Burlington is located near the geographic center of the Golden Horseshoe, a densely populated and industrialized region home to over 7.7M people. Part of the surrounding semi-rural area is included in the Ontario government's Greenbelt Plan Area. BHI's service area is illustrated in Figure 9.

1 **Figure 9 - Map of BHI's Service Area**

2

BHI is responsible for providing all regulated distribution services within its service area. Its distribution system has an almost even split of overhead to underground infrastructure, with 56% of its service area served by overhead infrastructure and 44% served by underground infrastructure.

BHI does not have any other LDCs embedded within its distribution system and it is not a host utility to other distributors. BHI's neighbouring electricity distribution utilities are:

- Alectra Utilities to the West;
- Milton Hydro to the North;
- Hydro One Networks to the Northeast; and
- Oakville Hydro to the East.

BHI's distribution system is supplied by Hydro One Networks Inc. ("HONI") from five TSs, namely Burlington TS, Cumberland TS, Bronte TS, Palermo TS and Tremaine TS. All TSs are owned and operated by HONI, up to and including the feeder breakers. BHI does not own or operate assets that operate at voltages greater than 50 kV.

BHI owns 34 distribution feeders egressing from the TS, all of which operate at 27.6 kV. Distribution transformers on the 27.6-kV system supply customers directly. BHI also owns 32 MSs, with 28 distribution feeders operating at 13.8 kV and 98 at 4.16kV, bringing the total number of distribution feeders to 160.

BHI does not have any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets and is not asking the OEB to deem any transmission or high voltage assets as distribution assets in this Application.

1.5 CUSTOMER ENGAGEMENT

1.5.1 Overview

The responsibility of informing, gathering feedback and responding to customer needs is one of BHI's top priorities. By engaging in a meaningful way with customers, BHI is better able to meet expectations and provide services that enhance the customer experience. In recent years BHI has embraced new ways to connect with customers – through web-based services, surveys, and employing social media platforms such as X, Facebook and Instagram. BHI uses the feedback from various engagement efforts to ensure it continues to deliver the value that customers expect.

1.5.2 Ongoing Customer Engagement

1.5.2.1 Ongoing Customer Engagement & Communication Activities

BHI is dedicated to ongoing customer engagement through various initiatives aimed at understanding and meeting customer needs. The annual Customer Satisfaction Survey, which includes feedback from residential and small business customers, has assisted BHI with identifying customer preferences and areas for improvement. While satisfaction scores remain high, BHI continuously strives to enhance its services based on customer feedback. In addition, the biennial Public Awareness of Safety Survey assesses public knowledge of electrical safety. BHI achieved an 85% Public Safety Awareness Index Score in 2024, indicating a strong understanding of key electrical safety precautions within BHI’s service territory.

BHI engages in community outreach efforts throughout the year such as participation in local events and initiatives. Post-event debriefings have revealed recurring themes, such as requests for more information on power outages and tree trimming. This feedback has informed the development of customer newsletters and targeted social media content. BHI has embraced digital tools, offering online platforms and real-time data that cater to customers’ preferences for self-serve options, providing them with quick access to essential information and services.

BHI communicates with customers through a variety of means, including its website, customer service department, social media platforms (X, Facebook, Instagram, and LinkedIn), on-bill messages and inserts, emails, media releases, the MyBurlingtonHydro portal, as well as booths at community events. This multichannel approach provides opportunities for customer feedback, ensuring effective communication and engagement.

1.5.2.2 Ongoing Customer Engagement Feedback

The feedback from BHI's ongoing customer engagement has highlighted a strong preference for digital communication methods, such as email and text alerts, especially related to billing issues and outage notifications. In response, BHI has prioritized enhancing its digital communication platforms to better align with customer expectations.

Customer Communication Preferences: BHI has observed a notable shift in customer communication preferences through its satisfaction surveys. Customers have expressed a strong preference for telephone and email as the primary methods for addressing billing issues. During planned outages, email alerts and notices are favored for timely updates. COVID-19 accelerated the demand for digital communications, with increased interest in receiving alerts for planned and unexpected outages, as well as billing issues. A 2021 UtilityPULSE survey highlighted that 52% of customers preferred email alerts for planned outages, while 38% favored text messages. Similarly, for unexpected outages, 47% preferred text message alerts, and 37% opted for email notifications. This surge in digital communication preferences aligns with broader trends in customer engagement, emphasizing the need for utilities to adapt to evolving communication expectations. BHI provides a sample of interactions from customers on communication preferences in Figure 1 of:
Attachment3_CustomerFeedback_Tweets_BHI_04162025.

Enhancing Outage Communications: In response to recurring feedback, BHI has prioritized enhancing outage communications. A significant majority of customers now desire the ability to report outages online and receive text alerts when power is restored, with text messages being the preferred medium over emails. In addition, frequent customer complaints indicated a strong desire for an enhanced public outage map. BHI provides a sample of feedback from customers on its outage map in Figure 2 of Attachment3_CustomerFeedback_Tweets_BHI_04162025. By integrating these insights into its operations, BHI ensures that its services remain responsive and aligned with the evolving needs of its customer base.

Further details on BHI's on-going customer engagement activities are provided in Appendix 2-AC of the OEB's Chapter 2 Appendices.

1.5.3 Application-Specific Customer Engagement

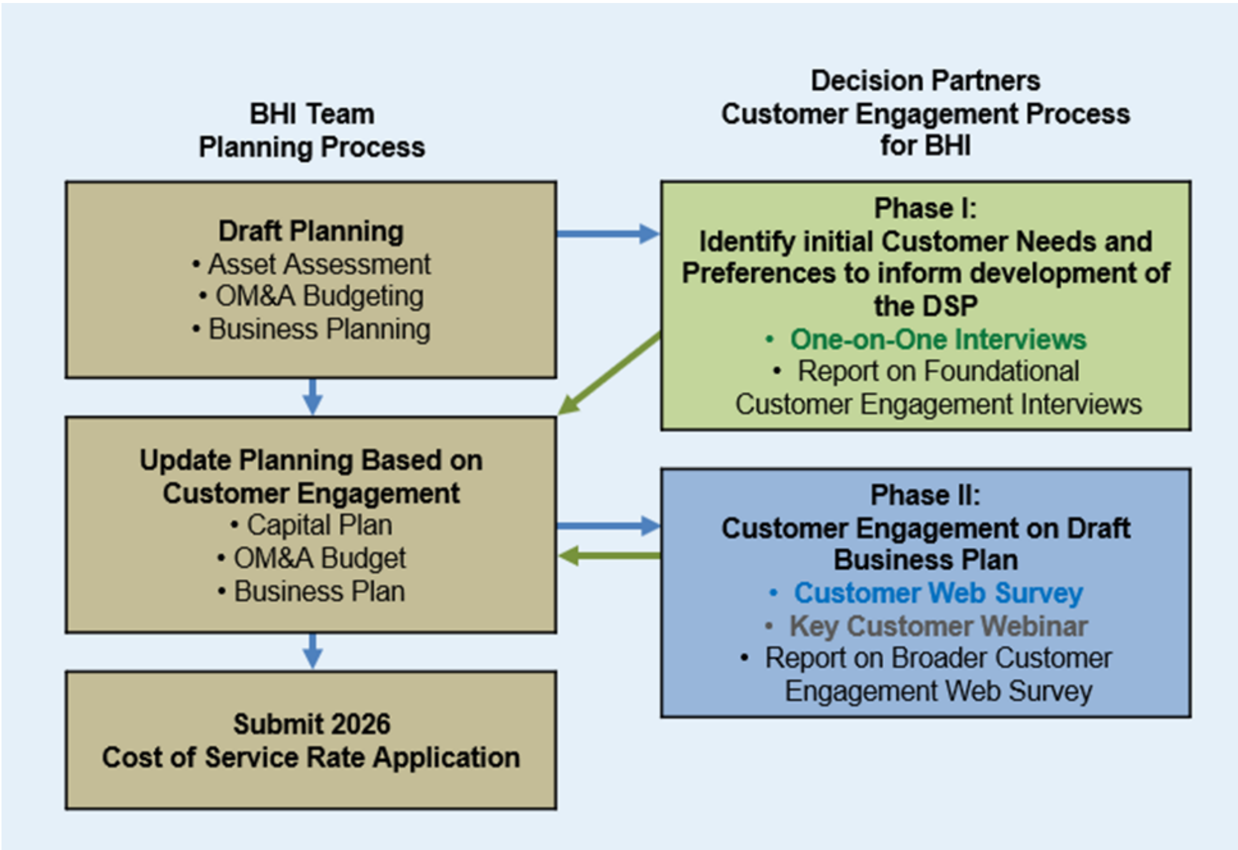
In February 2024, Decision Partners was engaged to support BHI's customer engagement process in support of its 2026 Cost of Service Application. The goal was to conduct customer engagement activities that would be used to inform the content and priorities for the DSP. Decision Partners applied its Mental Modeling Insight™ (MMI™) – strategic, evidence-based, science-informed processes, methods, and tools – to design and conduct a meaningful, respectful, and effective two-phase engagement process. MMI is specifically designed to elicit in-depth, reliable insight into people's mental models – their needs, values, interests, and priorities.

In total, more than 3,500 residential, small commercial and large commercial/industrial customers across a diverse cross-section of the Burlington community participated in the Application-Specific Customer Engagement process.

1.5.3.1 Approach

A two-phased approach was used to conduct the application-specific customer engagement activities.

Figure 10 - Application-Specific Customer Engagement Process



1.5.3.2 Phase I - Foundational Customer Engagement

In Phase I, foundational interviews were conducted with 36 of BHI's customers, between March 9 and April 9, 2024. This initial phase was designed to elicit in-depth and meaningful insight into customers' needs, values, interests, and priorities. The key objective of Phase I was to assess the alignment of BHI's values and priorities in the company's initial planning with those of its customers. The open-ended, conversational nature of the interviews, with follow-up prompting, provided an opportunity for unanticipated topics to arise and encouraged more in-depth responses. The small number of interviews is typical for foundational mental models-based research and is often followed-up with confirmatory research with a larger sample as was done with the Web Survey in Phase II.

Key themes identified through Phase I were as follows:

- Top strategic priorities are safety, reliability and affordability. Commercial customers showed more sensitivity to the frequency of outages as compared to residential customers, who were more concerned with duration.

- Strong alignment with tactical priorities of proactively replacing deteriorated infrastructure and upgrading the distribution system to respond to increasing extreme weather.

- Customers specifically highlighted the importance of outage communication, stressing the need to be informed about what is happening and BHI's response.

This feedback provided strategic direction into BHI's planning process and informed the development of its draft capital expenditure plan along with factors such as asset condition and system performance.

1.5.3.3 Phase II - Broad Customer Engagement

In Phase II, BHI's draft capital expenditure plan was presented to customers through a customer engagement Web Survey, open to all customers, and a Key Customer Webinar targeted at Commercial and Industrial customers.

Decision Partners designed and conducted the Web Survey, open to all of BHI's customers between August 13 to September 15, 2024. The purpose of the Web Survey was to confirm customers' needs, values, interests, and priorities – based on a much larger sample of BHI's customers – as well as obtain feedback on updated business planning priorities, including the four categories of capital spending in the DSP: System Access, System Renewal, System Service, and General Plant; and the associated impact on customers' bills. The input from the Web Survey was then used by BHI to update and finalize the capital budget underpinning the Application.

Decision Partners also supported BHI in designing and facilitating a Key Customer Webinar held on September 10, 2024. BHI invited its approximately 950 large commercial and industrial customers (GS>50kW) to participate in the Key Customer Webinar. The webinar, which was attended by eight participants, presented details of the business plan and offered an opportunity to comment on the draft plan and/or ask questions of BHI. In addition to attending the webinar, key customers were also encouraged to provide their feedback by completing the Web Survey, if they had not already done so.

1.5.3.4 Application-Specific Customer Engagement Results

The results indicated that there is strong customer alignment with BHI on the company's core strategic priorities – that electricity delivery be safe, reliable, and at prudent and value-based rates. More than 90% of customers agreed that BHI's capital expenditure priorities are important. Customers were most supportive of investments of "proactively replacing deteriorated infrastructure", "upgrading the distribution system to respond to increasing extreme weather", and "investing in new and innovative technology". After being presented with the overall bill impact of BHI's proposed plan, more than 80% of customers said that the level of spending was appropriate. The Web Survey results were consistent with the results of the foundational interviews which identified customers' top priorities for the electricity industry in general as cost, affordability, reliability, green energy, infrastructure capacity, and energy conservation.

Customer Outage Communication: Results from the Web Survey and the foundational interviews show that some customers may be unaware of the cause of outages and what is being done to restore power, and some customers indicated that they would like more information during outages. This suggests that customers would value enhanced communication, perhaps through the use of automated or customer-oriented systems that provide more, and more timely, information about outages, including causes, response times and actions that BHI is taking to prevent future occurrences. The open-ended responses from the Foundational Interviews provided some more in-depth insight into customers' perceptions on this topic.

In the Web Survey, customers were asked specifically about causes of outages. While customers are aware of general causes such as adverse weather, defective equipment, and human interaction (such as car accidents), most customers – including over 50% of residential customers in the Web Survey – also reported having outages that they didn't know the cause of.

Several customers provided optional comments when rating their customer experience, that further supports they value enhanced communication.

Electrification and Grid Modernization: The Web Survey results show that nearly all customers understand and support the need for investments in new and innovative technology to support grid modernization. Customers were specifically asked about changing electricity needs and how likely they were to have electric vehicles, solar panels, battery storage, and heat pumps in the next 10 years. While customers' responses varied for each, a significant number of customers indicated that they were likely to add each of these technologies. This suggests the potential for significant change in customers' electricity needs that BHI must plan and prepare for, particularly for EVs and heat pump systems, that would result in an increase in customer demand for electricity.

Alignment on Capital Spending Priorities and Plans: Customers were generally accepting of the rationale and appropriateness for planned spending in the four categories of capital spending as presented in the Web Survey, with more than 90% of customers agreeing that BHI's capital expenditure priorities are important. System Renewal was the highest rated category, and General Plant was the lowest rated.

Understanding and Alignment on Impact of Capital Spending on Customer Bills: Web Survey respondents were shown a summary of impacts of the proposed spending on customer bills. After being presented with the Overall Bill Impact, approximately 80% of customers rated the level of planned spending as appropriate. A comparison of the subset of residential customers who indicated that they participate in a financial support program to residents overall, did not appear to indicate any meaningful difference in customer perceptions of the overall appropriateness of proposed spending.

Confidence in Burlington Hydro: Most customers in both the foundational interviews and Web Survey expressed a high degree of confidence in BHI to "continue to provide safe, reliable and affordable electricity."

Key Takeaways for Business Planning: The key takeaways from BHI's application-specific customer engagement are as follows:

- Customers are in alignment with BHI's strategic priorities for safe, reliable electricity delivery.
- Customers are aware of the challenges of maintaining the distribution system in the face of more frequent extreme weather events and changes to the way people use electricity.
- Customers are not always aware of the cause of outages and what is being done to respond to them, and expressed a need for better communications and communications systems.
- A significant number of customers indicated that their personal electricity usage will change with the adoption of EVs and heat pump systems in the next ten years.
- Customers indicated strong support for BHI's draft spending and capital investment plan, while also expressing concerns about the high price of electricity (and resulting electricity bills).
- Customers were most supportive of efforts for System Renewal and System Service investments – maintaining the existing system and modernizing it to adapt to coming changes.
- Customers expressed a high degree of confidence in BHI's ability to provide safe, reliable, and affordable electricity.

Although the majority of customers showed a high level of support for the proposed plan, a subset of customers indicated that the overall bill impact of BHI’s proposed plan wasn’t appropriate. BHI incorporated this feedback into its plan through targeted reprioritization and re-pacing of expenditures to address customer concerns, specifically:

- Cutting a proposed voltage conversion program from the capital expenditure plan, eliminating $2.8 million from the DSP period;
- Re-pacing metering expenditures to mitigate the overall bill impact; and
- Re-pacing certain General Plant expenditures to mitigate the overall bill impact.

BHI’s final capital expenditure plan is responsive to customer feedback while addressing critical distribution system needs in order to continue providing service quality outcomes customers value. Further details are provided in BHI's Customer Needs and Preferences Survey attached as Appendix C to this Exhibit 1.

1.6 PERFORMANCE MEASUREMENT

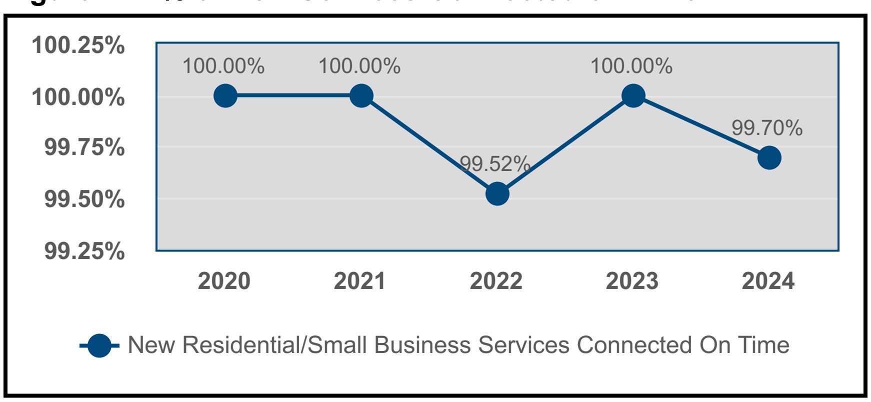
1.6.1 Performance Monitoring and Benchmarking

The OEB expects distributors 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. BHI includes its 2023 OEB scorecard as Appendix F in this Exhibit 1 which is also available on the OEB's website[24]. BHI discusses its performance for each of the distributor's scorecard measures over the last five years below where available, including forward-looking performance targets it has set for itself in this Application.

1.6.1.1 New Residential Services Connected on Time

BHI connected new residential and small business services on time over 99% of the time over the 2020-2024 period as identified in Figure 11 below. BHI field staff manage the day-to-day activities of its field crews to ensure that this service quality measure is met. BHI plans to continue to exceed the OEB target of 90%.

Figure 11 - % of New Services Connected on Time



1.6.1.2 Scheduled Appointments Met on Time

BHI met 100% of its scheduled appointments on time over the 2020-2024 period as identified in Figure 12 below. Engineering and construction staff use an electronic calendar to schedule and manage appointments in support of meeting this service quality measure. BHI plans to continue to exceed the OEB target of 90%.

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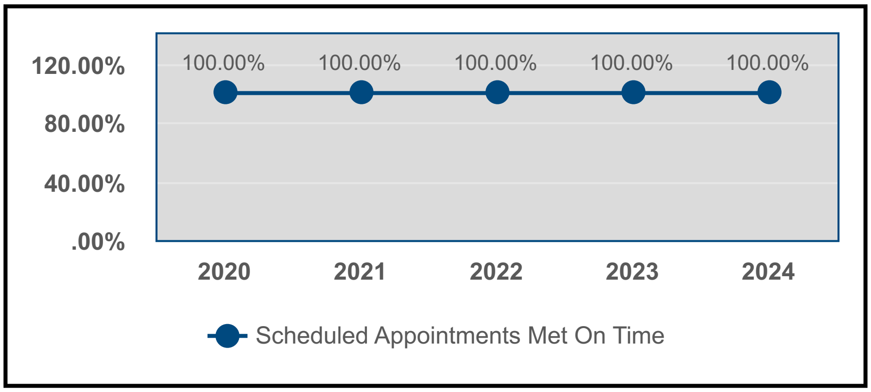
[24] https://www.oeb.ca/_html/performance/report_builder_dist_display.php?showdist=Burlington%20Hydro%20Inc.

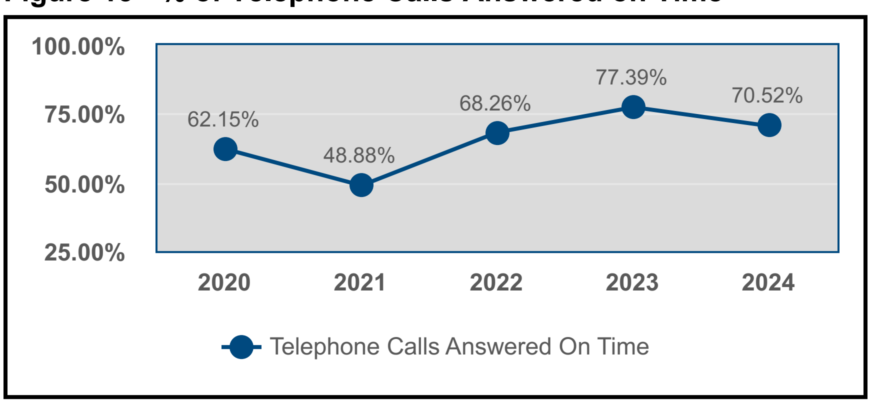
Figure 12 - % of Scheduled Appointments Met on Time



1.6.1.3 Telephone Calls Answered On Time

BHI has exceeded the target of 65% for answering customer phone calls within 30 seconds for three out of the last five years as identified in Figure 13 below. BHI's performance was below target in 2020 due to an increase in the number of customer enquiries about new customer billing and payment programs introduced to offer customers more billing flexibility in response to COVID-19. BHI's performance was below target in 2021 due to (i) resources were diverted to the implementation BHI’s CIS conversion project; and (ii) an increased volume and duration of customer enquiries regarding the Regulated Price Plan ("RPP") Customer Choice initiative and RPP pricing changes.

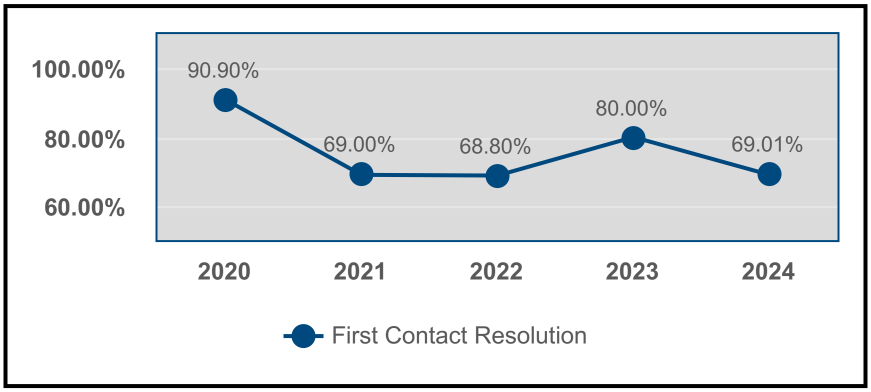
Figure 13 - % of Telephone Calls Answered on Time



1.6.1.4 First Contact Resolution

BHI resolved customer concerns on first contact more than 69% of the time over the 2020-2024 period as identified in Figure 14 below. BHI aims to address its customers’ needs as quickly as possible and resolve customer concerns the first time the customer contacts BHI. In addition to its call centre, BHI uses a number of online electronic request forms that customers are able to complete themselves. These forms contribute to the high rate of First Contact Resolution.

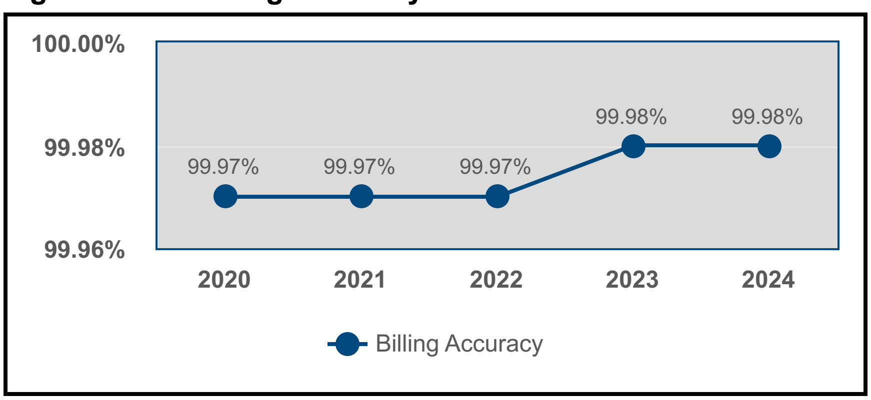
Figure 14 - % of First Contact Resolution



1.6.1.5 Billing Accuracy

BHI issued an accurate bill more than 99.97% of the time over the 2020-2024 period as identified in Figure 15 below. BHI's continuous attention to detail and rigorous business processes have contributed to this performance. BHI plans to continue to exceed the OEB target of 98%.

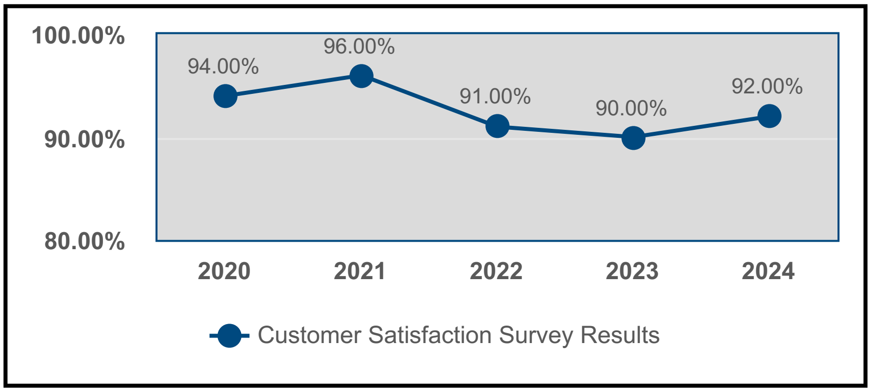
Figure 15 - % Billing Accuracy



1.6.1.6 Customer Satisfaction Survey Results

Engaging customers in a constantly changing energy environment is increasingly important. BHI commissions a customer satisfaction survey on an annual basis and these survey results provide valuable insights into customers' perceptions, needs and preferences both over time and relative to other LDCs. BHI consistently achieves a customer satisfaction result of over 90% as identified in Figure 16 below and targets to achieve or exceed the provincial average.

Figure 16 - Customer Satisfaction Survey Results

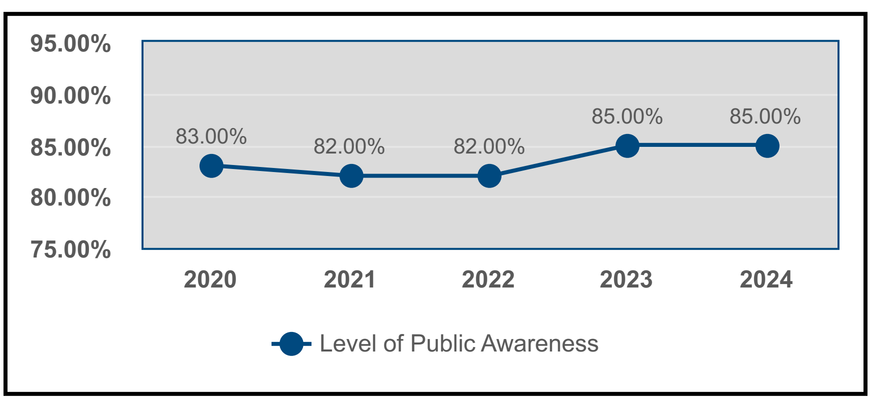


1.6.1.7 Level of Public Awareness

BHI conducts a public awareness survey among a representative sample of its territory population. The survey measures awareness levels of key electrical safety concepts related to distribution assets and is based on a standard survey methodology developed by the Electrical Safety Authority ("ESA"). BHI's Level of Public Awareness has exceeded 80% over the 2020-2024 period as identified in Figure 17 below. Initiatives that contribute to this level of awareness include:

- Responding, as requested, to public inquiries received through BHI's Health and Safety
- email box;
- Elementary school programs and children safety programs;
- Public safety video messaging; and
- City of Burlington Emergency Preparedness exercise.

Figure 17 - Level of Public Awareness



1.6.1.8 Level of Compliance with O.Reg. 22/04

Ontario Regulation 22/04 - Electrical Distribution Safety establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. BHI was compliant with Ontario Regulation 22/04 over the 2020-2024 period and plans to remain compliant in the future.

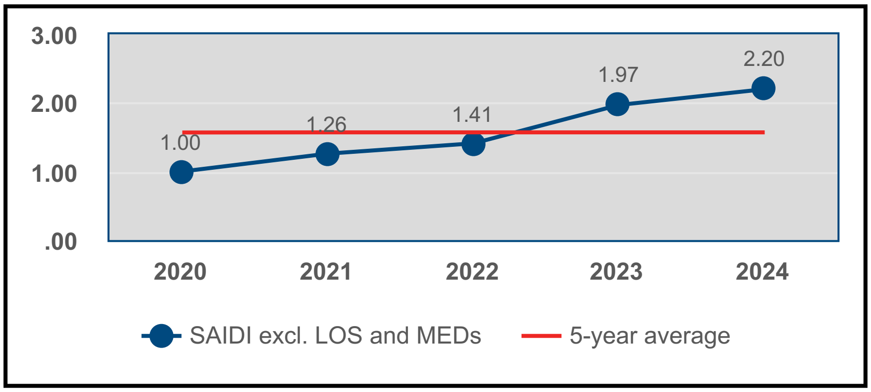
1.6.1.9 Serious Electrical Incident Index: Number of General Public Incidents

BHI reported one serious electrical incident in 2021, related to a contractor cutting into a primary underground cable. As a result of this, BHI missed its target for the Number of General Public Incidents and the Rate of Serious Electrical Incidents per 10, 100, 1000 km of line. The incident was reported to the Electrical Safety Authority ("ESA") and the Ministry of Labor, which conducted an investigation.

1.6.1.10 SAIDI

BHI’s average System Average Interruption Duration Index (“SAIDI”) performance, excluding Loss of Supply (“LOS”) and Major Event Days (“MEDs”), was 1.57 over the 2020-2024 period as identified in Figure 18 below. i.e., on average, customers experienced just over one and a half hours in sustained interruptions annually, after adjusting for events beyond BHI’s control (LOS and MEDs). SAIDI performance was higher than the target of 1.19 in each of 2021-2024 due to a significant increase in the number of outages caused by defective equipment and adverse weather. This increase is discussed in further detail in Section 1.2.4 C.1 of this Exhibit 1. BHI’s average SAIDI performance increased from 1.19 over the 2015-2019 period, to 1.57 over the 2020-2024 period, indicating customers are experiencing a longer duration of outages. BHI's target for SAIDI for the 2026-2030 rate term is 1.57 based on its five year historical average from 2020-2024. BHI's reliability objectives are discussed in further detail in Section 5.2.3.1.1 of the DSP.

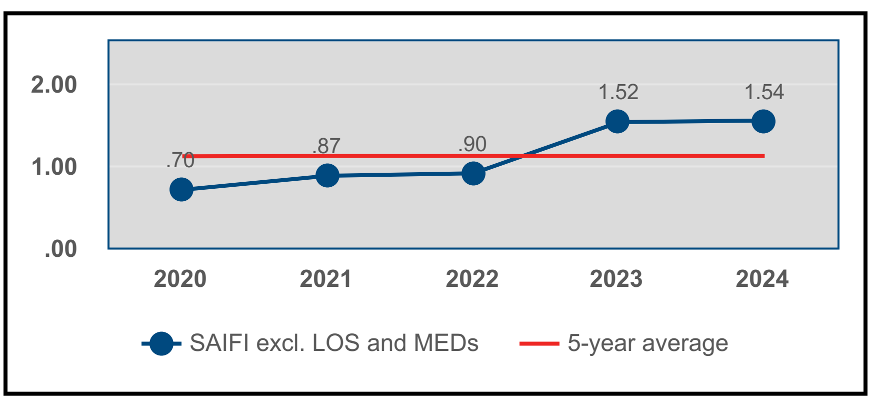
Figure 18 - SAIDI excl LOS and MEDs



1.6.1.11 SAIFI

BHI’s average System Average Interruption Frequency Index (“SAIFI”) performance, excluding LOS and MEDs, was 1.11 over the 2020-2024 period, as identified in Figure 19 below. i.e., on average, customers experienced more than one sustained interruption annually, after adjusting for events beyond BHI’s control (LOS and MEDs). BHI’s SAIFI performance was worse than the target of 0.75 in every year except 2020 for the same reasons identified in Section 1.6.1.10 above. BHI's target for SAIFI for the 2026-2030 rate term is 1.11 based on its five year historical average from 2020-2024. BHI's reliability objectives are discussed in further detail in Section 5.2.3.1.1 of the DSP.

Figure 19 - SAIDI excl LOS and MEDs



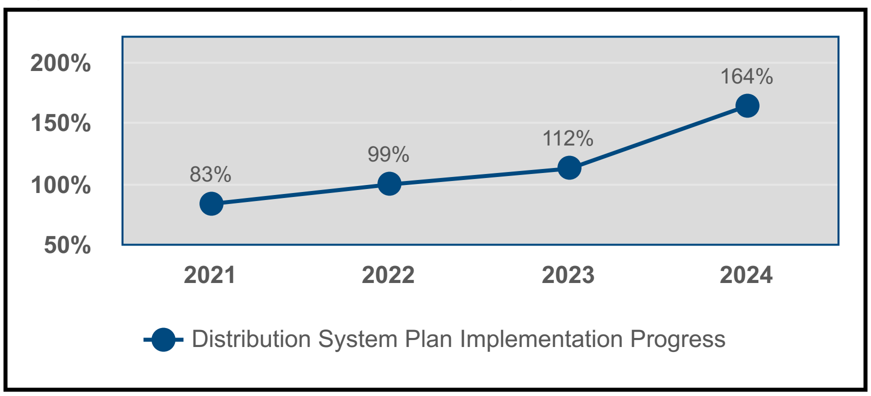
1.6.1.12 DSP Implementation Progress

The "DSP Implementation Progress" metric is intended to assess Burlington Hydro's effectiveness at planning and implementing its DSP, and is calculated as actual annual capital expenditures as a percentage of the planned annual capital expenditures approved in its DSP.

$$\text{DSP Implementation Progress \%} = \frac{\text{Annual Actual Capital Expenditures}}{\text{Annual Planned Capital Expenditures}}$$

BHI provides its annual actual capital expenditures as a percentage of its annual planned capital expenditures in Figure 20 below. BHI is not reporting results in 2020 as it did not have a OEB-approved DSP for the 2019-2020 period. Planned expenditures for the historical period are based on BHI's DSP for capital expenditures approved in its 2021 Cost of Service application.

Figure 20 - DSP Implementation Progress

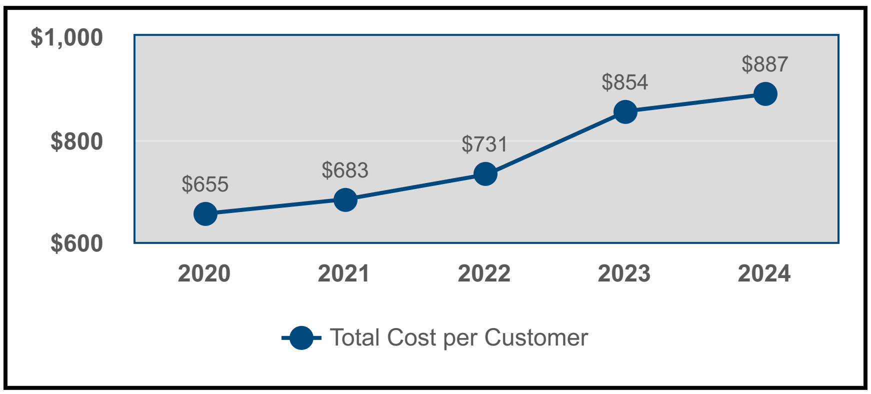


Actual capital expenditures in 2021 were 83% of BHI's planned capital expenditures, primarily due to delays in the implementation of third-party infrastructure relocation projects as a result of design changes and other delays caused by road authorities. BHI's actual capital expenditures in 2023 were 112% of its planned capital expenditures. BHI's actual capital expenditures in 2024 were 164% of its planned capital expenditures, primarily due to the unexpected upgrade of its wholesale revenue metering equipment at the Burlington TS, the reactive replacement of faulty/ leaking transformers, higher than planned reactive cable replacements, higher than planned building expenses due to the emergency replacement of a leaking section of roof at its head office, and the implementation of a new OMS to better manage and respond to power outages, and streamline restoration efforts. Further detail is provided in Section 5.4.1.1 of the DSP.

1.6.1.13 Total Cost per Customer

Total cost per customer is calculated as the sum of BHI's capital and operating costs divided by the total number of customers that BHI serves. BHI's total cost per customer per year is identified in Figure 21 below, and has increased by an average of 7.9% per year over the 2020-2024 period. BHI has experienced increases in its total costs required to deliver quality and reliable services to customers. The drivers of the increase in total cost per customer are discussed in further detail in Sections 1.2.4 C.3 and 1.2.4 D.2 of this Exhibit 1.

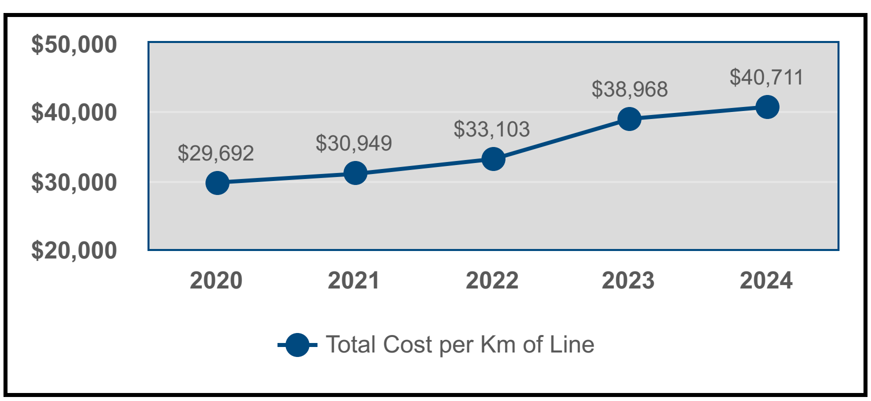
Figure 21 - Total Cost per Customer



1.6.1.14 Total Cost per Km of Line

Total cost per km of line is calculated as the sum of BHI's capital and operating costs divided by the kilometers of line that BHI operates to serve its customers. BHI's total cost per km of line is identified in Figure 22 below and has increased by an average of 8.2% per year over the 2020-2024 period, which is consistent with the increase in total cost per customer.

Figure 22 - Total Cost per Km of Line



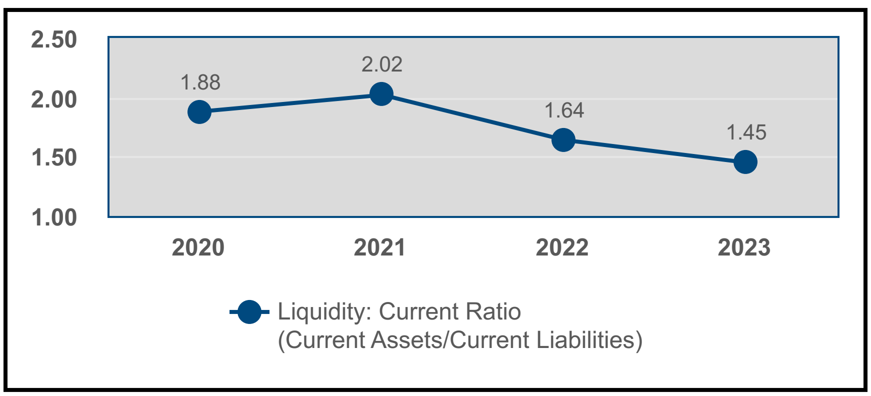
1.6.1.15 New Micro-embedded Generation Facilities Connected On Time

The OEB requires electricity distributors to connect new micro-embedded generation facilities (Net Metering projects of less or equal than 10 kW) 90% of the time within the prescribed time frame of five business days. BHI engages a consulting firm to assume overall responsibility for processing its connections. BHI connected new micro-embedded generation facilities within five business days more than 100% of the time over the 2020-2024 period and plans to continue this performance.

1.6.1.16 Liquidity: Current Ratio

The current ratio measures whether BHI has sufficient resources to meet its short-term debts/ obligations (due within the next 12 months). BHI's current ratio is identified in Figure 23 below, and has exceeded 1.45 over the 2020-2023 period, indicating it can settle its short-term debts with existing assets. 2024 is unavailable at the time of filing.

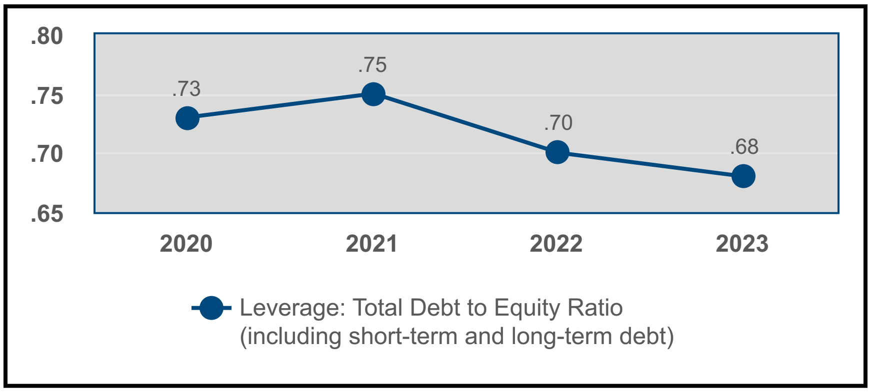
Figure 23 - Liquidity: Current Ratio



1.6.1.17 Leverage: Total Debt to Equity Ratio

The total debt-to-equity ratio measures the extent to which the assets of a company are financed by borrowing money. A debt-to-equity ratio of 1.00 means that half of the assets of a business are financed by debts and half by shareholders' equity. The OEB uses a deemed capital structure of 60% debt and 40% equity when establishing rates for electricity distributors, which is equal to a debt-to-equity ratio of 1.5 (60/40). BHI's total debt-to-equity ratio is identified in Figure 24 below, and was below the OEB's deemed debt-to-equity ratio of 1.5 over the 2020-2023 period. 2024 is unavailable at the time of filing.

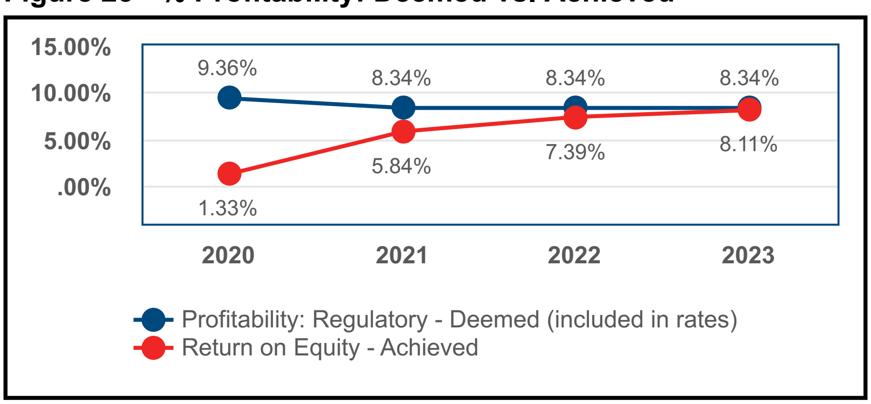
Figure 24 - Leverage: Total Debt to Equity Ratio



1.6.1.18 Profitability: Deemed vs. Achieved

BHI's current distribution rates were approved by the OEB in the Settlement Agreement of its 2021 Cost of Service application and include an expected (deemed) regulatory return on equity of 8.34%. The OEB allows electricity distributors to earn within +/- 3% of the deemed return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB. With the exception of 2020, BHI's achieved return on equity over the 2020-2023 period was within the 5.34% - 11.34% range allowed by the OEB, as identified in Figure 25 below. 2024 is unavailable at the time of filing.

Figure 25 - % Profitability: Deemed vs. Achieved



1.6.2 Efficiency Assessment

Electricity distributors must manage their costs successfully in order to ensure customers are receiving appropriate value for the cost of service. The total costs of Ontario electricity distributors are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The OEB publishes a report each year on the benchmarking of electricity distributor cost performance based on this evaluation. As described in the OEB's Report of the Board on *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*[25], an econometric model is used to generate these efficiency rankings. Electricity distributors are divided into five cohorts based on the magnitude of the difference between their respective individual actual and predicted costs. These rankings are based on a three-year average cost performance.

BHI provides its historical cost performance and efficiency assessment performance from 2019 to 2023 in Table 20 below. BHI was assigned to Cohort 2 from 2019 to 2023.

Table 20 – Historical Cost Performance

Description	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals
Percentage Difference (Cost Performance)	(11.7)%	(13.0)%	(11.7)%	(13.5)%	(10.0)%
Three-Year Average Performance	(12.5)%	(12.9)%	(12.1)%	(12.8)%	(11.7)%
Stretch Factor Cohort - Annual (Three Year Average)	**2**	**2**	**2**	**2**	**2**
Rate Year	2021	2022	2023	2024	2025

BHI provides a forecast of its efficiency assessment using the PEG forecasting model for the 2026 Test Year in Table 21 below, for the purposes of providing the OEB with a directional indication of efficiency. This model is attached as:

Attachment2_Benchmarking_Spreadsheet_Forecast_Model_BHI_04162025.

[25] EB-2010-0379, p23

Table 21 – Forecast of Efficiency Assessment

Description	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
Actual Total Cost	$59,075,631	$61,717,631	$67,587,882	$73,659,218
Predicted Total Cost	$65,280,800	$68,710,231	$72,053,619	$74,254,871
Actual Cost Greater Than/(Less Than) Predicted Cost	$(6,205,170)	$(6,992,600)	$(4,465,738)	$(595,653)
Percentage Difference (Cost Performance)	**(10.0)%**	**(10.7)%**	**(6.4)%**	**(0.8)%**
Three-Year Average Performance	(11.7)%	(11.4)%	(9.0)%	(6.0)%
Stretch Factor Cohort - Annual	3	2	3	3
Stretch Factor Cohort - Annual (Three Year Average)	2	2	3	3

BHI expects to be assigned to Group 3 for the next Price Cap IR term (2026-2030), and costs in the 2026 Test Year are expected to align with predicted values. The change in BHI's cohort ranking is due to an increase in costs associated with the need to, among other things, sustain a safe, reliable and resilient grid; connect and serve customer demand in a growing city; respond to evolving policy and customer expectations in response to the energy transition; and protect customer data and the grid against intensifying cyber security threats. These drivers and the associated increase in total costs are discussed in further detail in Sections 1.2.4 C.3 and 1.2.4 D.2 of this Exhibit 1.

1.6.3 IRM Increases and Cohort Assignments

BHI provides a summary of its OEB-approved IRM increases and cohort assignments for each of 2022-2025 in Table 22 below.

Table 22 - Summary of Historical IRM Increases, Stretch Factors and Cohort Assignments

Years	Inflationary Increase	Stretch Factor	OEB Approved IRM Increase	Cohort Assignment
2022	3.30%	0.15%	3.15%	II
2023	3.70%	0.15%	3.55%	II
2024	4.80%	0.15%	4.65%	II
2025	3.60%	0.15%	3.45%	II

1.6.4 Activity and Program-based Benchmarking

The OEB announced OEB announced changes to the Activity and Program-Based Benchmarking ("APB") framework in line with its commitment to encourage continuous improvement by regulated utilities and increase regulatory efficiency . On October 17, 2024, the OEB published its APB report with unit cost results for ten programs for results up to 2023.

BHI provides its unit cost variance analysis for each of the ten programs below.

1.6.4.1 Billing O&M

BHI's billing O&M costs are 56% lower than the 2019-2023 industry average as identified in Table 23 below. BHI cannot comment on why its billing O&M costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in Account 5315. BHI records the costs associated with operating its Billing Program, as defined in Section 4.3.0.3 of Exhibit 4, in Account 5315. The costs associated with operating its Customer Service Program, including collections management, credit management, and call centre, as defined in Section 4.3.0.6 of Exhibit 4, are recorded elsewhere.

Table 23 - Billing O&M Cost ($) per Customer vs. Industry Average

Billing O&M Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$11.80	$13.57	$17.04	$19.03	$18.00	**$15.89**
YoY Change		15 %	26 %	12 %	(5)%	
Industry						$36.41
vs. Industry Average						**(56)%**

BHI's billing costs in 2025 are expected to be 25% higher than 2024, as identified in Table 24 below, due to higher Canada Post mailing costs, which increased approximately 26% effective January 2025 to better align stamp prices with the rising cost of providing letter mail service to all Canadians. This also accounts for the increases of 36% and 42% in 2025 and 2026 respectively as compared to BHI's five-year average.

Table 24 - Billing O&M Cost ($) per Customer YoY Change

Billing O&M Cost ($) per Customer	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$17.23	$21.57	$22.58
YoY Change	(4)%	25 %	5 %
vs. 5-year Average	8 %	36 %	42 %

1.6.4.2 Metering O&M

BHI's metering O&M costs are 36% lower than the 2019-2023 industry average as identified in Table 25 below. BHI cannot comment on why its metering costs are significantly lower than the industry average without visibility into what costs other LDCs are recording in this Program. The costs associated with operating BHI's Metering Program are identified in Section 4.3.0.13 of Exhibit 4.

Table 25 - Metering O&M Cost ($) per Customer vs. Industry Average

Metering O&M Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$10.17	$12.77	$13.56	$11.29	$14.14	**$12.38**
YoY Change		26 %	6 %	(17)%	25 %	
Industry						$19.43
vs. Industry Average						**(36)%**

BHI's metering costs in 2024-2026 are expected to be within 15% of prior year and BHI's five-year average as identified in Table 26 below.

Table 26 - Metering O&M Cost ($) per Customer YoY Change

Metering O&M Cost ($) per Customer	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$12.25	$13.39	$13.52
YoY Change	(13)%	9 %	1 %
vs. 5-year Average	(1)%	8 %	9 %

1.6.4.3 Vegetation Management O&M

BHI's historical average cost per pole of $52.01 is 34% higher than the industry average, as identified in Table 27 below.

Table 27 - Vegetation Management O&M Cost ($) per Pole vs. Industry Average

Vegetation Management O&M Cost ($) per Pole	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$40.74	$52.64	$34.84	$45.32	$86.49	**$52.01**
YoY Change		29 %	(34)%	30 %	91 %	
Industry						$38.76
vs. Industry Average						**34 %**

BHI surmises that this difference is due to the size of the City of Burlington's urban forests and tree canopy. BHI performs vegetation management on 161 overhead primary feeders extending almost 1,000 circuit kilometres along Burlington's arterial thoroughfares, rights-of-way, and residential streets. The City of Burlington's wooded natural areas cover more than 5,500 hectares with 71,000 trees along streets and in parks. Some of BHI's overhead distribution system runs along/through these wooded areas.

BHI will continue to drive down unit costs by awarding its vegetation management contracts through a competitive bidding and evaluation process every three years, with the latest contracts awarded for 2025-2027. The tendering process is designed to award the contract to multiple vendors for multiple years based on several criteria to maximize customer value. BHI selects the lowest price which satisfies competence, safety and experience requirements.

BHI will maintain its vegetation management practices as follows to proactively mitigate against storm damage and associated system reliability risks:

- prune trees and branches according to minimum clearance standards based on the American National Standards Institute ("ANSI") A300 – Standard Practices for Trees, Shrubs and other Woody Plant Maintenance, and the City of Burlington's Urban Forest Master Plan; and
- clear three meters in from the high voltage lines or wires (primary distribution system) in all directions to address three years of growth. This is an established utility practice based on Electrical Safety Authority ("ESA") guidelines.

BHI is proposing a significant increase in spending in vegetation management in 2025 and 2026 where costs are 72% and 19% higher than prior year respectively, as identified in Table 28 below.

Table 28 - Vegetation Management O&M Cost ($) per Pole YoY Change

Vegetation Management O&M Cost ($) per Pole	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$56.89	$97.57	$116.43
YoY Change	(34)%	72 %	19 %
vs. 5-year Average	9 %	88 %	124 %

Vegetation management costs are increasing in 2025 and 2026 due to:

- an increase in the fixed price costs for scheduled vegetation management services. These costs are based on market pricing and account for 80% of the increase in costs from the 2021 Actuals to the 2026 Test Year; and
- additional tree trimming for customers and emergency vegetation management primarily due to increasing extreme weather in BHI's service territory - this accounts for 16% of the increase in costs from the 2021 Actuals to the 2026 Test Year.

These increases are discussed in more detail in Section 4.3.0.7 of Exhibit 4.

1.6.4.4 Lines O&M

BHI's historical average lines cost per cct km of Primary Line of $3,103 is 68% higher than the industry average, as identified in Table 29 below. Further, BHI's unit costs have increased from $2,548 in 2019 to $3,724 in 2023. BHI has experienced and continues to experience a significant increase in outages due to defective equipment and adverse weather as identified in Figure 2 and Figure 3 in this Exhibit 1, respectively. These outages require immediate corrective action to repair and restore assets to their normal operating condition to reduce safety risk to crews and the public, and restore power. An increase in the frequency of these type of outages leads to increased OM&A costs, as more resources than originally scheduled are required to restore power. Standby crews and contractors are called in at overtime and premium rates respectively, particularly when outages occur outside of business hours. BHI crews are shifted from regularly scheduled O&M work and proactive capital replacements to reactive operating maintenance and repairs.

Table 29 - Lines O&M Cost ($) per cct km of Primary Line vs. Industry Average

Lines O&M Cost ($) per cct km of Primary Line	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$2,548	$2,687	$3,258	$3,298	$3,724	**$3,103**
YoY Change		5 %	21 %	1 %	13 %	
Industry						$1,849
vs. Industry Average						**68 %**

Lines costs in 2024, 2025 and 2026 are 31% and 39% higher than BHI's 5-year average, respectively, as identified in Table 30 below, for the reasons described above. Year-over-year increases are between 4% and 6%.

BHI plans to drive down unit costs by (i) increasing capital expenditures to replace infrastructure at the end of its useful life and in poor/very poor health condition, as proposed in Section 5.4.1.2.2 of the DSP which may mitigate repair and troubleshooting costs in the medium term (2027 and onwards); and (ii) mitigating the impact of more frequent and severe extreme weather events by system hardening and proactive grid planning as identified in Sections 5.2.1.3 and 5.4.1.2.2 of the DSP.

Table 30 - Lines O&M Cost ($) per cct km of Primary Line YoY Change

Lines O&M Cost ($) per cct km of Primary Line	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$3,881	$4,063	$4,324
YoY Change	4 %	5 %	6 %
vs. 5-year Average	25 %	31 %	39 %

1.6.4.5 Stations O&M

BHI's historical average cost per total MVA of $2,323 is 83% higher than the industry average, as identified in Table 31 below. BHI has large number of substations as compared to other LDCs - 32 substations which house 44 substation power transformers. The industry average, based on BHI's review of Cost of Service applications for other LDCs is 18 (excluding Hydro One). Further, as identified in BHI's ACA, many of BHI's stations assets are in poor and very poor health, specifically Station Primary Switchgears, Station Protective Relays and Station Buildings

(25 of the 32 substations are comprised of buildings). As such, required ongoing operations and maintenance for both equipment and buildings, as discussed in Section 4.3.0.16 of Exhibit 4, are likely higher than the industry average due to the volume and condition of assets.

Table 31 - Stations O&M Cost ($) per Total MVA vs. Industry Average

Stations O&M Cost ($) per Total MVA	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$2,053	$2,064	$2,561	$2,304	$3,276	**$2,323**
YoY Change		1 %	24 %	(10)%	42 %	
Industry						$1,272
vs. Industry Average						**83 %**

Stations O&M costs in 2025 and 2026 are 23% and 34% higher than BHI's 5-year average, respectively, as identified in Table 32 below, due to the declining health of station assets and the consequent increase in ongoing maintenance costs for both equipment and buildings. Unit costs may decline as BHI replaces and refurbishes its stations equipment and building over the next rate period, however it still expects to be well over the industry average based on the number of stations required to service its customers safely and reliably.

Table 32 - Stations O&M Cost ($) per Total MVA YoY Change

Stations O&M Cost ($) per Total MVA	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$2,704	$2,868	$3,117
YoY Change	(17)%	6 %	9 %
vs. 5-year Average	16 %	23 %	34 %

1.6.4.6 Poles, Towers and Fixtures O&M

BHI's historical average cost per pole of $6.34 is 43% lower than the industry average, as identified in Table 33 below. BHI does not have visibility into why its average cost per pole is significantly lower than the industry average. BHI does have a low level of expenditures in this program as compared to the number of poles (over 15,000). Typically any maintenance required for Poles, Towers and Fixtures is minimal. The majority of the work relates to replacements and is therefore capitalized.

Table 33 - Poles, Towers O&M Cost ($) per Pole vs. Industry Average

Poles, Towers O&M Cost ($) per Pole	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$14.96	$2.93	$4.80	$7.36	$1.66	**$6.34**
YoY Change		(80)%	64 %	53 %	(77)%	
Industry						$11.10
vs. Industry Average						**(43)%**

Poles and Towers O&M costs in 2024, 2025 and 2026 are identified in Table 34 below.

Table 34 - Poles, Towers O&M Cost ($) per Pole YoY Change

Poles, Towers O&M Cost ($) per Pole	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$2.06	$1.76	$1.89
YoY Change	24 %	(15)%	8 %
vs. 5-year Average	(67)%	(72)%	(70)%

1.6.4.7 Stations Capex

BHI's historical average Stations capital expenditures per MVA of $469 are 90% lower than the industry average, as identified in Table 35 below. There are significant fluctuations year over year during the historical period:

- In 2022, BHI replaced a higher-cost transformer with an on-load tap changer feature at Lowville MS in 2022, which accounts for the increase of 151% as compared to 2021. This feature enhanced voltage regulation and system reliability, contributing to higher capital costs.
- In 2023, capital expenditures decreased by 73% versus prior year. Partial payment was made for a transformer replacement in 2023 at Howard MS, whereas a full transformer replacement at the Lowville MS was undertaken in 2022. Further, no switchgear was replaced in 2023 vs. one replacement in 2022.

Table 35 - Stations CAPEX Cost ($) per Total MVA vs. Industry Average

Stations CAPEX Cost ($) per Total MVA	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$105	$209	$486	$1,220	$325	**$469**
YoY Change		99 %	132 %	151 %	(73)%	
Industry						$4,616
vs. Industry Average						**(90)%**

Stations capital expenditures per total MVA in 2024, 2025 and 2026 were or are expected to be 265%, 348%, and 373% higher than BHI's 5-year average, respectively as identified in Table 36 below. However expenditures are still expected to be significantly lower than the industry average of $4,616 per total MVA.

- In 2024, the increase of 428% vs. 2023 or 265% vs. the five year average in the unit cost index is due to the full replacement of a transformer in 2024, compared to only partial replacement work completed in 2023. Further, one switchgear was replaced in 2024 vs. no replacements in 2023.
- In 2025 and 2026, the increases versus prior years and the five year average are driven by higher forecasted expenditures for transformer replacement, switchgear and circuit breakers.

Table 36- Stations CAPEX Cost ($) per Total MVA YoY Change

Stations CAPEX Cost ($) per Total MVA	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$1,713	$2,103	$2,216
YoY Change	428 %	23 %	5 %
vs. 5-year Average	265 %	348 %	373 %

1.6.4.8 Poles, Towers and Fixtures Capex

BHI's historical average for Poles, Towers and Fixtures capital expenditures per number of poles installed of $16,792 are 59% higher than the industry average, as identified in Table 37 below. There can be significant variability in the cost of pole replacements, dependent upon pole specifications (height and type of poles) and the number of circuits required. There are significant fluctuations in unit costs year over year during the historical period:

- In 2022, average capital expenditures decreased by 45% as compared to prior year. Replacement projects for poles can be either brand new installations or selective replacement of defective components only. The latter projects generally have a lower unit cost as they require fewer material and labour inputs compared to new installations, which are more capital intensive and require full assembly, including pole structures, hardware, and circuits. In 2022, BHI had fewer new installations than in 2021, resulting in a lower cost per pole.
- In 2023, average capital expenditures increased by 69% as compared to prior year due to a higher proportion of new pole and tower installations as compared to prior year.

Table 37 - Poles, Towers CAPEX Cost ($) per Pole Installed vs. Industry Average

Poles, Towers CAPEX Cost ($) per Pole Installed	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$12,377	$16,132	$22,380	$12,282	$20,787	**$16,792**
YoY Change		30 %	39 %	(45)%	69 %	
Industry						$10,533
vs. Industry Average						**59 %**

Poles and towers capital expenditures per pole in 2024, 2025 and 2026 were or are expected to be 69%, 40%, and 134% higher than BHI's 5-year average, respectively as identified in Table 38 below. This is due to rising material and labour costs, as well as variations in pole specifications (height and type of poles) and the number of circuits required.

As part of its 2026-2030 pole replacement program, discussed in Section 5.4.1.2.2 of the DSP, BHI plans to implement cost mitigation measures by reinforcing poles with a proprietary PoleEnforcer System[26], where feasible, rather than proceeding with full replacements. This approach aims to extend asset life, reduce failures, and defer replacements.

[26] PoleEnforcer Brochure 11-15.pdf

Table 38 - Poles, Towers CAPEX Cost ($) per Pole Installed YoY Change

Poles, Towers CAPEX Cost ($) per Pole Installed	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$28,396	$23,471	$39,335
YoY Change	37 %	(17)%	68 %
vs. 5-year Average	69 %	40 %	134 %

1.6.4.9 Line Transformer Capex

BHI's historical average for line transformer capital expenditures of $14,383 per number of transformers installed is 17% higher than the industry average, as identified in Table 39 below. In 2023, costs increased by 39% as compared to prior year, driven by:

- cost increases beyond inflation (BHI's average purchase price of transformers increased by over 55% from 2020 to 2024); and
- variations in the types of transformers replaced (e.g., differences in rating and the use of higher-cost pad-mounted transformers instead of pole-mounted transformers).

Table 39 - Line Transformer CAPEX Cost ($) per Transformer Installed vs. Industry Average

Line Transformers CAPEX Cost ($) per Transformer Installed	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$16,286	$9,602	$14,485	$13,170	$18,371	**$14,383**
YoY Change		(41)%	51 %	(9)%	39 %	
Industry						$12,287
vs. Industry Average						**17 %**

Line transformer capital expenditures per transformer in 2024, 2025 and 2026 were or are expected to be 23%, 67%, and 95% higher than BHI's 5-year average, respectively as identified in Table 40 below. These increases are driven by cost pressures as identified above, and variations in the types of transformers replaced (e.g., differences in rating and the use of higher-cost pad-mounted transformers instead of pole-mounted transformers).

Table 40 - Line Transformers CAPEX Cost ($) per Transformer Installed YoY Change

Line Transformers CAPEX Cost ($) per Transformer Installed	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$17,678	$24,054	$28,053
YoY Change	(4)%	36 %	17 %
vs. 5-year Average	23 %	67 %	95 %

1.6.4.10 Meters Capex

BHI's historical average for meter capital expenditures per customer of $11.89 is 3% lower than the industry average, as identified in Table 41 below. The increase in unit cost in 2023 of 182% as compared to 2022, was driven by the multi-year meter resealing and reverification project undertaken to comply with Measurement Canada regulations.

Table 41 - Meters CAPEX Cost ($) per Customer vs. Industry Average

Meters CAPEX Cost ($) per Customer	2019	2020	2021	2022	2023	Average 2019-2023
Burlington Hydro Inc.	$7.47	$11.11	$8.11	$8.58	$24.18	**$11.89**
YoY Change		49 %	(27)%	6 %	182 %	
Industry						$12.22
vs. Industry Average						**(3)%**

Meter capital expenditures per customer in 2024, 2025 and 2026 were or are expected to be 35%, 88%, and 400% higher than BHI's 5-year average, respectively as identified in Table 42 below. The increases in 2024 and 2025 are driven by increases in the volume of meters requiring resealing and reverification to comply with Measurement Canada regulations. In 2026, the expected increase of 166% vs. prior year is due to the large-scale smart meter replacement project for meters, commencing in 2026. Full replacement has a higher per unit cost than resealing. The capital expenditures for this project are paced over the 2026-2030 rate period to smooth costs and workload over multiple years. This project is discussed in further detail in Section 5.4.1.2.1 in the DSP.

BHI expects its per unit cost to return to historical levels and the industry average when this replacement project is complete.

Table 42 - Meters CAPEX Cost ($) per Customer YoY Change

Meters CAPEX Cost ($) per Customer	2024 Actuals	2025 Forecast	2026 Forecast
Burlington Hydro Inc.	$16.07	$22.35	$59.47
YoY Change	(34)%	39 %	166 %
vs. 5-year Average	35 %	88 %	400 %

1.7 FACILITATING INNOVATION

BHI's approach to innovation focuses on the deployment of new and advanced processes and technologies to (i) enhance grid performance and operational processes, and (ii) deliver incremental value to customers. BHI provides its achievements and future plans to advance innovation across the organization below.

1.7.1 Transformational Innovation

BHI continues to invest in technologies to prepare for electrification and contribute to grid modernization.

- **OMS:** BHI's new OMS facilitates better alignment with strategic objectives - specifically, addressing customer needs more effectively and efficiently; and enhancing operational efficiencies. It has improved BHI's ability to manage and respond to power outages, and streamline restoration efforts which in turn improves overall grid resiliency. The new OMS will ensure timely, accurate and proactive two-way communication with customers using various communications channels which were not available options in BHI's legacy system. Customers have indicated that they would like to be notified of planned and unplanned outages through texts or email alerts and messages, functionality which was not available in BHI's legacy OMS.

  The new OMS provides real time monitoring, automated fault location and reduced downtime. BHI plans to utilize proactive notification, reporting and performance metrics, and integrate with other components of the grid. Enhanced reliability and grid resiliency will help drive down the total cost of ownership in the long term by lowering operational costs and improving asset management. The new OMS will integrate directly with relevant systems to, for example: provide real-time system visibility and control during outages, and allow for SMS communications. This will allow for faster restoration times, improved outage communication to customers, and a more robust outage portal. In addition to operational improvements, the new OMS will streamline the reporting process by automating tasks that were previously handled manually, increasing both efficiency and accuracy. Additionally, the new system is built to support future grid modernization initiatives, enabling advanced functionalities like FLISR, Volt-Var Optimization (“VVO”), and Distributed Energy Resources Management System (DERMS). These capabilities will help BHI continue to reduce outage times, improve system efficiency, enhance customer experience and support the integration of renewable energy sources into the grid. By leveraging real-time data, automation, and integration with advanced technologies, the new OMS enables faster outage detection and resolution, better resource management, and proactive communication with customers.

- **SCADA Replacement and ADMS Acquisition:** BHI is seeking approval through this Application to replace its aging SCADA system and procure an integrated ADMS. These upgrades would modernize grid operations by enabling real-time monitoring, predictive analytics, and automated fault detection, leading to faster outage response, improved reliability, and optimized system performance. Integration with BHI's new OMS would streamline operations and support future capabilities such as DER integration, demand response, and voltage optimization, to deliver enhanced customer service and meet evolving regulatory and cyber security requirements. The SCADA Replacement and ADMS Acquisition is discussed in further detail in Section 5.4.1.2.4 of the DSP.

- **GridSmartCity Cooperative and DSO Readiness:** As an active member of the GridSmartCity Cooperative, BHI participates in collaborative innovation initiatives, including Distribution System Operator ("DSO") readiness research and work addressing technical, operational, and collaborative steps, resources, and standardization across LDCs in order to achieve a more flexible and efficient distribution system in the future.

- **Cable Injection Program:** BHI is extending the life of aging underground cable assets through a targeted cable injection program. This method is significantly more cost-effective than full replacement—typically 3 to 5 times less expensive—and allows BHI to refurbish cables which are beyond their expected service life. By deferring capital replacement, this approach supports long-term asset management and avoids capital replacement costs while ensuring system reliability for customers. This program is discussed in further detail in Section 5.2.1.3 of the DSP.

1.7.2 Process and Operational Improvement

BHI continuously improves internal processes through automation and digital tools that enhance operational efficiency, examples of which are provided below:

- **Automated Accounts Payable (AP) Workflow:** BHI implemented a cloud-based software in 2025 which automated its invoice payment process through the ability to scan, route, approve and store invoices electronically. Introduced in 2025, this intelligent capture solution integrates with BHI's ERP and streamlines invoice processing, increases operational efficiency, improves the timing of the approval process for invoices and payments, results in a positive environmental benefit through the elimination of paper records, facilitates better tracking and record-keeping, and eliminates the need for physical presence.

- **Electronic Funds Transfer ("EFT") Implementation:** BHI has implemented EFT for vendor payments, streamlining the payment process, reducing reliance on paper cheques, and improving payment accuracy, security and speed. This digitized approach enhances financial controls, reduces the risk of fraud, has a positive environmental benefit, facilitates better tracking and record-keeping, eliminates the need for physical presence, and strengthens vendor relationships.

- **Workiva Platform for Financial and Regulatory Reporting:** BHI has implemented Workiva, a cloud-based reporting platform that simplifies, centralizes and connects both financial and regulatory reporting, resulting in improved data accuracy and collaboration, faster turnaround times, and increased efficiency in preparing rate applications.

- **Health, Safety and Environment Management System ("HSEMS"):** BHI has implemented an HSEMS, a centralized digital platform that allows for the digitization of key safety processes and workflows, including inspections, incident reporting, training tracking, and compliance documentation. As an extension of this system, the SafeTapp app enables mobile access to training records, certifications, policies, and safety procedures, ensuring that employees can access up-to-date information on the go. This integrated, paperless approach enhances workplace safety, improves operational efficiency, and ensures regulatory compliance, contributing to safety excellence and a more responsive workforce. Further details on BHI's HSEMS are provided in Section 4.3.0.15 of Exhibit 4 in this Application.

- **Contractor Compliance Software:** BHI implemented Contractor Compliance, a digital platform that streamlines the tracking and management of contractor qualifications, certifications, and safety documentation. This tool enhances oversight, improves compliance with internal and regulatory safety standards, and ensures that all contractors working on BHI’s behalf meet BHI's standards and expectations for health, safety, and accountability.

1.7.3 Customer-Focused Innovation

BHI’s approach to innovation includes a strong focus on customer-centric improvements that expand access, streamline communication, and enhance the overall customer experience including the following:

- **MyAccount Customer Portal:** BHI implemented a new customer account portal to better serve its customer base and enable it to implement the Green Button platform, discussed in further detail below. This secure, self-service portal gives customers 24/7 access to account balances, billing history, energy usage, rate plan options, and e-billing registration. The portal allows customers to perform service requests such as move-in/ move-out, change electricity price plans, link to BHI's outage map, and provides access to the Green Button platform. These tools empower customers to manage their electricity usage and make informed energy choices.

- **Interactive Voice Response ("IVR") & Cloud-Based Phone System:** BHI’s upgraded IVR platform allows customers to report outages, request callbacks, track their place in the queue, and receive personalized, automated messaging. This enhances accessibility and reduces wait times while maintaining a high standard of customer care. This upgrade is discussed in more detail in Section 4.3.0.6 in Exhibit 4 in this Application.

- **Digital Customer Service Forms:** BHI implemented enhanced Customer Service Forms on its website and customer portal. These digital forms provide customers with electronic confirmation numbers upon submission and are electronically submitted to online work queues for completion. Customers can provide/update banking information, open/close service accounts and submit requests to change rate plans. The automation of these forms reduces delays and errors, delivering faster service and greater transparency. BHI plans to further enhance this feature by integrating these forms with its CIS system to reduce redundancy.

- **Green Button Implementation:** The Green Button platform, mandated to be implemented across all Ontario LDCs by the Province of Ontario, was designed to empower residents and businesses by providing detailed insight into their energy consumption. BHI enhanced its MyAccount Customer Portal in order to implement this initiative (in December 2023) which helps customers manage their electricity usage and provides them with greater control over their energy consumption.

  Through the Green Button platform, households and businesses can effortlessly access and securely download detailed energy data and authorize its automatic transfer to third party Green Button applications of their choosing. Using the Green Button platform customers can:

  - Gain a comprehensive understanding of their energy usage, enabling informed decision-making.
  - Select the most suitable electricity price plan tailored to their specific needs.
  - Track and analyze energy consumption trends, facilitating optimization and cost savings.
  - Make informed decisions regarding energy efficiency upgrades, promoting sustainability and reducing environmental impact.

  By leveraging the Green Button platform, customers can make smarter energy choices, ultimately leading to greater efficiency, cost savings, and environmental stewardship.

- **"Works" Web Portal:** BHI enhanced its website to include an engineering and operations portal called "Works". The portal provides customers with more information about BHI's engineering and operations services such as automated forms for new service or upgrades, DERs and net metering. It also includes general educational information regarding EVs and other emerging technologies, power outages, and safety around electrical equipment. This facilitates achievement of BHI's goal to increase transparency, trust and confidence in its ability to serve its customers. The ability of customers to quickly and efficiently access services through the website in a user friendly manner contributes to a positive customer experience.

1.7.4 Enabling a Culture of Innovation

BHI has taken steps to structure its workforce and systems to encourage innovation throughout the organization:

- **Organizational Realignment:** Two FTE positions were reallocated from the Engineering Program to the Information Services Program to establish a dedicated IT Manager, Projects and Business Applications, and a Business Applications/Data Specialist. The new roles in Information Services were required to (i) manage the increase in the volume of work associated with increased operational technology projects, (ii) enhance IT/OT governance, (iii) enable integration with other operational technologies, and (iv) reduce cyber security risk and shadow IT (i.e. any software, hardware or information technology resource used on an enterprise network without the IT department's approval, knowledge or oversight). This change is discussed in further detail in Section 4.3.1.1 in Exhibit 4 of this Application.

- **Collaborative Innovation Networks:** Through its membership in the GridSmartCity Cooperative and engagement in sector-wide forums, BHI continues to explore shared services and joint pilot programs that expand access to emerging technologies while sharing costs across LDCs. These partnerships help bring scalable solutions to customers more affordably.

1.8 FINANCIAL INFORMATION

1.8.1 Financial Statements

BHI attaches its non-consolidated 2024 Audited Financial Statements (“AFS”), which include the years 2023 and 2024, as Appendix G to this Exhibit 1.

1.8.2 Reconciliation of Financial Statements

A detailed reconciliation between the AFS and the regulatory financial results are attached as Appendix H to this Exhibit 1.

1.8.3 Annual Report and Management’s Discussion and Analysis

BHI, nor its parent company BEC, produce publicly available annual reports or MD&As. BHI attaches its 2023 Community Report as Appendix I to this Exhibit 1.

1.8.4 Rating Agency Reports

BHI does not have any rating agency reports and there are no plans for public issuances.

1.8.5 Prospectuses and Information Circulars

BHI does not have any publicly traded debt or equity and there are no plans to issue public debt or equity.

1.8.6 Change in Tax Status

BHI is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service application in 2021. BHI has not, nor is planning any future change in tax status.

1.8.7 Existing Accounting Orders

BHI has the following accounting orders, specific to BHI, which are discussed in further detail in Section 1.3.10.3:

- Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project
- Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project

1.8.8 Departures from the Uniform System of Accounts (“USoA”)

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

1.8.9 Accounting Standards

BHI transitioned to Modified International Financial Reporting Standards as of January 1, 2015 and has prepared this Application on that basis.

1.8.10 Non-Distribution Business

BHI is not conducting non-distribution businesses.

1.9 DISTRIBUTOR CONSOLIDATION

BHI has not acquired or amalgamated with any other distributor.

1.10 IMPACTS OF COVID-19 PANDEMIC

1.10.1 Background

The World Health Organization declared the COVID-19 outbreak a pandemic on March 11, 2020. On March 17, 2020, the Government of Ontario declared a state of emergency under the Emergency Management and Civil Protection Act ("EMCPA") to help fight the spread of COVID-19. The City of Burlington declared a state of emergency on March 21, 2020.

BHI responded quickly and effectively to COVID-19 to (i) ensure the safety of its employees, contractors and customers; and (ii) continue to deliver electricity safely and reliably and to the same standards in place prior to COVID-19. In addition to the impact to BHI and its customers and employees as a whole, significant changes in the distribution operations were required. The specific actions that BHI took are provided in Section 9.1.6.2 of Exhibit 9.

BHI reflects the impacts of COVID-19 in this Application as outlined below.

1.10.1.1 Load Forecast (COVID-19 Impact)

COVID-19 resulted in lower consumption and demands in BHI's service territory in 2020 and 2021 as compared to 2019. During this period, consumption increased for the Residential rate class as BHI's residential customers worked from home and spent more time at home due to provincial "Stay-at-Home" orders. Consumption and billed demands for General Service (commercial) customers decreased as residents worked from home and the economy experienced an economic downturn. The change in loads due to COVID-19 are reflected in the load forecast with economic variables. The economic variables used include Gross Domestic Product ("GDP") from the Ontario Economic Accounts[27] and FTEs from Statistics Canada. The reduction in economic activity correlated with the reduction in General Service loads through COVID-19.

[27] https://www.ontario.ca/page/ontario-economic-accounts

BHI has made specific adjustments to its load forecast for, among other things, the adoption of EVs. COVID-19 has had an impact on the availability of EVs and as such the total number of Ontario vehicle sales has fluctuated in recent years. The impact of EV adoption to BHI's load forecast is discussed in further detail in Section 3.1.1.8 of Exhibit 3 of this Application.

1.10.1.2 Capital Forecast (COVID-19 Impact)

COVID-19 disrupted global supply chains, affecting the availability of critical components and materials needed by BHI for infrastructure maintenance and development. Challenges included transportation delays, shortages of essential supplies, and increased costs. These issues made it difficult for BHI to procure necessary equipment and materials in a timely manner. Some of these issues continue to impact BHI's capital forecast, such as cost increases and longer lead times for critical components as identified below. Between 2020 and 2024:

- Pole prices increased by an average of 55%, with lead times increasing by 102%, resulting in a 15 day delay;
- Underground copper cable prices increased by an average of 99%, with lead times increasing by 95%, resulting in a nine day delay;
- Transformers prices increased by an average of 55%, with lead times increasing by 77% resulting in a 50 day delay; and
- Switches prices increased by an average of 37%, with lead times increasing by 145%, resulting in a 155 day delay.

These challenges underscore the lasting impact of COVID-19 on material availability and cost predictability within the utility industry.

BHI has incorporated known factors into its DSP attached as Appendix A to Exhibit 2.

1.10.1.3 Operating Expenses (COVID-19 Impact)

BHI incurred incremental operating costs from 2020 to 2022 as a direct result of its response to COVID-19; specifically costs associated with (i) air-gapping crews by setting up separate control room and operations centres; (ii) implementing temporary work from home protocols; (iii) increasing cleaning services; and (iv) purchasing COVID-19 supplies such as hand sanitizer, wipes and masks. These measures are discussed in further detail in Section 9.1.6.2 of Exhibit 9.

In addition to incremental operating costs directly related to BHI's COVID-19 response, operating costs were impacted across several programs in other ways such as:

- staff were shifted from capital to operating work due to a deferral in customer connection requests and capital work in 2021.
- BHI had difficulty completing services for which it relied on contractors e.g. vegetation management contractors had difficulty retaining staff who left to collect the Federal Government's Canada Emergency Response Benefit ("CERB").
- digitalization has increased since BHI's last Cost of Service application, in part due to COVID-19 and the consequent shift to remote work and online services. As a result, IT/ OT support for BHI customers and employees has increased to meet their evolving needs.
- COVID-19 accelerated the demand for digital communications, with increased interest from customers in receiving alerts for planned and unexpected outages, as well as billing issues, as discussed above in Section 1.5.2.2.

Further details are provided in the variance analysis section of the programmatic evidence in Section 4.3 of Exhibit 4.

1.10.1.4 Deferral Account (COVID-19 Impact)

In March 2020, shortly after the Ontario Government declared a state of emergency in response to the spread of COVID-19 in the province, the OEB established a deferral account in which rate-regulated utilities could record incremental costs related to the pandemic. On June 27, 2021, the OEB released a report addressing Regulatory Treatment of Impacts Arising from the COVID-19 Emergency[28] ("COVID Report"). The report provided guidance on the rules and operations of the account including criteria for an applicable means test, cost sharing and criteria for recording amounts.

BHI has recorded (i) its incremental costs related to COVID-19 and (ii) realized savings from reduced insurance premiums and reduced spending on conferences, seminars and workshops

[28] EB-2020-0133 Report of the Ontario Energy Board, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, June 17, 2021

in the deferral account. The result of these entries is a balance of $320,439, including carrying charges to December 31, 2025, which BHI is proposing to dispose of as part of the Group 2 DVA balance in this Application. Further details are provided in Section 9.1.6 of Exhibit 9.

APPENDICES

Appendix A – Cost of Service Checklist

2026 Cost of Service Checklist

Burlington Hydro Inc.

EB-2025-0051

Date: April 16, 2025

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	Confirmed
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 Confidential Filings, as applicable).	Exhibit 1, Appendix D
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 D
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 D
Ch2, p2	A letter from the governing body (e.g., Board of Directors) certifying that it is aware of and approves the submission of the application	Exhibit 1, Appendix E
2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit 1, Section 1.0 and Appendix A
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Attachment1_OEB_Chapter2Appendices_BHI_04162025 ; Attachment14_Excel_Current_Tariff_Sheet_BHI_04162025 and Exhibit 8, Appendix A
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was updated/amended	Confirmed
3	Regulated entity shown seperately from parent company or any other affiliates	Confirmed
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	N/A, as BHI has filed this Application as scheduled
4 & 5	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	N/A
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	Confirmed, Exhibits 1 to 9
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed, Exhibits 1 to 9
6	Documents must include page numbers and be provided in text searchable and bookmarked PDF format	Confirmed, Exhibits 1 to 9
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed
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	Exhibit 1, Section 1.2.5; Exhibit 2, Section 2.1.1.1; Exhibit 4 and Section 4.1.1
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	Exhibit 1, Section 1.1
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, Section 1.2.3 and Appendix B
7-9	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 1.2.4
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit 1, Section 1.3.3
9	Identification of legal (or other) representation	Exhibit 1, Section 1.3.4
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 1.3.5
9	Statement identifying where notice should be published and why	Exhibit 1, Section 1.3.6
9	Form of hearing requested and why	Exhibit 1, Section 1.3.7

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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 1.3.8
10	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1, Section 1.3.9
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 1.3.10
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, Sections 1.3.11 and 1.3.12
10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the organization; 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 management of the parent company. 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.	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, Sections 1.5.2 and 1.5.3; Attachment1_OEB_Chapter2Appendices_BHI_04162025, App. 2-AC_Customer Engagement
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 1.5.2
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 1.5.3 and Appendix C
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 1.5.3 and Appendix C
12	All responses to matters raised in letters of comment filed on public record	BHI has not received any letters yet, BHI commits to file them as part of the proceeding of this Application
Performance Measurement		
12	Link to most recent scorecard	Exhibit 1, Appendix F
12	Identification of performance improvement targets	Exhibit 1, Section 1.6.1
12	OEB approved benchmarking model for the test year showing efficiency assessment, discussion on how the results obtained from the OEB approved forecasing model and Activity and Program-based Benchmarking (APB) have informed the distributor's business plan and application	Exhibit 1, Sections 1.6.2 and 1.6.4 and Attachment2_Benchmarking_Spreadsheet_Forecast_Model_BHI_04162025
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 the OEB approved model	Exhibit 1, Section 1.6.3
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 - An explanation of significant change (greater than 20% from previous year or five-year average) - A plan to drive down unit costs if five-year average is 25% greater than industry five-year average	Exhibit 1, Section 1.6.4
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 1.6.4
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. An innovative approach the OEB has emphasized is for distributors to consider the use of non-wires solutions (NWSs) to address distribution system needs	Exhibit 1, Section 1.7
Financial Information		
15	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	Exhibit 1, Section 1.8.1 and Appendix G
15	A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non-distribution businesses. This must include the identification of any deviations that are being proposed between the audited financial statements and the regulatory financial results, including the identification of any prior OEB approvals for such deviations.	Exhibit 1, Section 1.8.2 and Appendix H

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
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	Exhibit 1, Section 1.8.3
15	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	N/A - Exhibit 1, Section 1.8.4
15	Any change in tax status	N/A - Exhibit 1, Section 1.8.6
15	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1, Section 1.8.7
15	Accounting Standards used for financial statements and when adopted	Exhibit 1, Section 1.8.9
15	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	N/A - Exhibit 1, Section 1.8.10
Distributor Consolidation		
16	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	N/A - Exhibit 1, Section 1.9
16	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	N/A - Exhibit 1, Section 1.9
A distributor filing an application to rebase following a consolidation must:		
16	Identify any incentives that formed part of the consolidation 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	N/A - Exhibit 1, Section 1.9
16	Specify whether and which commitments made to shareholders are to be funded through rates	N/A - Exhibit 1, Section 1.9
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.)	N/A - Exhibit 1, Section 1.9
16	Detail of efficacy of any rate plan confirmed as part of MAADs	N/A - Exhibit 1, Section 1.9
16	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	N/A - Exhibit 1, Section 1.9
Distributor rebasing for the first time following a consolidation that approved under the 2024 MAADs handbook must provide: (Distributors that Deferred Rebasing for Five Years or Less)		N/A - Exhibit 1, Section 1.9
17	Achieved efficiencies and savings associated with the various activities where efficiencies were expected (as documented in the consolidation application)	N/A - Exhibit 1, Section 1.9
17	A qualitative discussion on enhanced reliability and service quality as a consolidated distributor	N/A - Exhibit 1, Section 1.9
17	A qualitative discussion on enhanced reliability and service quality on a rate zone basis	N/A - Exhibit 1, Section 1.9
17	Total transaction and transition costs, and whether those have been recovered over the term of the deferred rebasing period through the savings achieved	N/A - Exhibit 1, Section 1.9
17	A discussion on any obstacles encountered since consolidation and how the distributor managed those obstacles. If applicable, a discussion of how obstacles affected the consolidated entity from reaching its targets should also be included	N/A - Exhibit 1, Section 1.9
Distributor rebasing for the first time following a consolidation that approved under the 2024 MAADs handbook must provide: (Distributors that Deferred Rebasing for More than Five Years)		N/A - Exhibit 1, Section 1.9
17	Updates to information filed as part of mid-term report based on achieved results, including for any period not covered by the initial mid-term report	N/A - Exhibit 1, Section 1.9
17	An updated version of the revenue requirement analysis provided in the consolidation application based on information known at the time of the filing, and a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.	N/A - Exhibit 1, Section 1.9
Impacts of COVID-19 Pandemic		
17 & 18	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		
18	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
18	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	Exhibit 2, Section 2.1.1, Table 1
18	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit 2, Section 2.1.1, Table 2
Fixed Asset Continuity Schedule		
18	Completed Appendix 2-BA for each year - in Excel format	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App. 2-BA_Fixed Asset Cont
18 & 19	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
19	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit 2, Section 2.2, Table 3

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
19	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	N/A - Exhibit 2, Attachment1_OEB_Chapter2Appendices_BHI_04162025, App. 2-BA_Fixed Asset Cont
19	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Exhibit 2, Section 2.8
19	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit 2, Section 2.4.2
19	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	Exhibit 2, Section 2.4.3
Depreciation, Amortization and Depletion		
20	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	N/A - Exhibit 2, Section 2.4
20	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Exhibit 2, Section 2.4.2 and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App. 2-C_DepExp
20	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	N/A - Exhibit 2, Section 2.4.1
20	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
20	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 and Appendix C
21	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	N/A - Exhibit 2, Section 2.9.1
21	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
Allowance for Working Capital		
21	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
21&22	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	N/A - Exhibit 2, Section 2.5
22	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 and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App. 2-Za_Comm. Exp. Forecast and App. 2Zb_Cost of Power
22	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Exhibit 2, Section 2.5.1
Distribution System Plan		
22	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit 2, Section 2.6 and Appendix A
Policy Options for the Funding of Capital		
22&23	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. For projects with an expected capital cost of $2 million or more, excluding general plant investments, includes documentation of the consideration of NWSs to meet the identified system need that will be addressed by the project(s) as articulated in the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs (BCA Framework) to assess the economic feasibility of NWSs.	Exhibit 2, Section 2.7
23	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	Exhibit 2, Sections 2.7.1 and 2.7.2
23	Complete Capital Module Applicable to ACM and ICM	Attachment4_2026_ACM_ICM_Model_BHI_04162025
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
24	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
24	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	N/A - Exhibit 2, Section 2.8
24	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).	N/A - Exhibit 2, Section 2.8
24	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	N/A - Exhibit 2, Section 2.8
Capitalization		
25	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 and Appendix C
25	Overhead Costs: complete Appendix 2-D	Exhibit 2, Section 2.9.2 and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-D_Overhead

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25	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		
26	See Appendix A	N/A - Exhibit 2, Section 2.10
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	DSP, Section 5.2
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, Sections 5.2.1.2 and 5.4.1
Distribution System Plan		
Ch5, p5	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	N/A - DSP, Section 5.2
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
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, Sections 5.2.1.2 and 5.2.1.3
Coordinated Planning with Third Parties		
Ch5, p5&6	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, p6	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, p6	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 5.2.2.7
Ch5, p6	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	N/A - DSP, Section 5.2.2.7
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
Ch5, p6&7	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, p7	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
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	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-G_SQI
Ch5, p7&8	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, Section 5.2.3.2
Ch5, p8	Summary of major events that occurred since last cost of service	DSP, Section 5.2.3.2.2
Ch5, p8	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 5.2.3.2.3

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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, p9	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
Ch5, p9	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 undertake grid optimization using an approach that considers the distributor's whole system -consideration, where applicable, of assessing the use of distribution rate-funded NWSs, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, and other innovative technologies -demonstration that distributor has a planning process for future capacity needs, which must include, among other aspects, increased adoption of electric vehicles	DSP, Section 5.3.1.3
Ch5, p10	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, Sections 5.3.2.1 and 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	N/A - DSP, Section 5.3.2.3
Ch5, p10&11	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	N/A - 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
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, Sections 5.3.3.3
Ch5, p11	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	DSP, Section 5.3.3.3.4
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, Sections 5.3.3
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		
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, Sections 5.2.2.10 and 5.3.4.3
Ch5, p11&12	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	DSP, Section 5.3.4.2
Non-Wires Solutions to Address System Needs		
Ch5, p12	Description of how distributor has taken NWSs into consideration in its planning process	DSP, Section 5.3.5
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 NWS, and the prioritization of proposed NWS activity relative to other system investments in the DSP	DSP, Section 5.3.5
Ch5, p12&13	Evidence why the proposed NWS is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts, following the requirements of the BCA Framework.	DSP, Section 5.3.5
Ch5, p13	Demonstration that distributor has meaningfully explored contracting services from non-utility owned distributed energy resources for any rate funded, distributor-owned NWS proposal	DSP, Section 5.3.5
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 5.4.1
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, Sections 5.4.1
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
Ch5, p13	Completed Appendices 2-AA and 2-AB	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-AA_Capital Projects and App.2-AB_Capital Expenditures
Ch5, p13&14	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

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Ch5, p14	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, benefit-cost analysis (BCA) 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, Section 5.4.2.1 and Appendix A
Ch5, p15&16	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 NWSs,if applicable), benefits for customers, impact on distributor costs -If a distributor is requesting funding for an NWS, additional guidance on evidentiary requirements is provided in the NWS Guidelines	DSP, Appendix A
Ch5, p16	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, 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 A
Benefit-Cost Analysis Framework		
The BCA Framework is mandatory when the projected capital cost of the proposed solution to an electricity system need (either NWS or traditional infrastructure) exceeds $2 million (excluding general plant investments)		N/A - DSP, Section 5.3.5
Ch5, p17	Conduct pre-assessment to identify whether there is a reasonable expectation that an NWS may be a viable approach to meeting an identified need. Should the pre-assessment conclude that an NWS is a viable approach, a distributor should proceed with completing a BCA. The BCA should be filed along with the pre-assessment results	
Ch5, p17	BCAs are to be prepared for each specific system need	N/A - DSP, Section 5.3.5
Ch5, p17&18	Distribution Service Test (DST) A distributor looking to file a BCA **must** employ the mandatory distribution service BCA and consider the mandatory quantitative/qualitative impacts to benefit/costs as outlined in the BCA Framework, and **must** include the Excel-based quantitative output template, BCA Data Filing Submission Template. The BCA **may** include the permitted DST qualitative impacts as applicable.	N/A - DSP, Section 5.3.5
Ch5, p18&19	Energy System Test (EST) Distributors **are encouraged** to do an optional EST particularly if they believe an NWS offers significant benefits beyond those of distribution service. When an EST is conducted, the mandatory EST quantitative/qualitative impacts should be included, including the DST impacts as outlined in the BCA Framework.	N/A - DSP, Section 5.3.5
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, Section 5.3.4
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	DSP, Section 5.3.4.2
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
26	Weather normal load forecast provided	Exhibit 3, Section 3.1.1.7 Tables 6, 10, 14,16, 17, 19 and 20 and Attachment5_Load_Forecast_Model_BHI_04162025
26	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Exhibit 3, Section 3.1.1
26	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, Sections 3.1.1.1, 3.1.1.2, 3.1.1.3 and 3.1.1.4
26	Explanation of weather normalization methodology	Exhibit 3, Section 3.1.1.1

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26	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-IB_Load_Forecast_Analysis and Attachment7_2025_RRWF_BHI_04162025, Tab 10. Load Forecast
27 & 28	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 and NWS impacts and other exogenous factors have been accounted for in the historical period, and how CDM and NWS impacts, including any 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 and Attachment5_Load_Forecast_Model_BHI_04162025
28	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 and NWS impacts and other exogenous factors have been accounted for in historical period and how CDM and NWS impacts, including any targets or forecasts in the bridge and test years, are factored into test year forecast -discussion of weather normalization assumptions used	N/A - Exhibit 3, Section 3.1.1
Incorporating CDM and NWS Impacts in the Load Forecast for Distributors		
28	Refer to NWS Guidelines for guidance, including supporting evidence required regarding incorporating historical and forecast impact of CDM and NWS acitivities in load forecast	Exhibit 3, Section 3.1.3
Accuracy of Load Forecast and Variance Analyses		
28	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-IB_Load_Forecast_Analysis
29	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, Sections 3.2.1 and 3.2.3
29	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 3.2.2 and 3.2.3
29	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Attachment5_Load_Forecast_Model_BHI_04162025
EXHIBIT 4 - OPERATING EXPENSES		
Overview		
29&30	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, Sections 4.1.0 to 4.1.5
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		

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30	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit 4, Section 4.2, and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JA_OM&A_Summary_Analys
30	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit 4, Section 4.2, and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JB_OM&A_Cost_Drivers
30	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JC_OM&A Programs
30	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-L_OM&A_per_Cust_FTE
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	Exhibit 4, Section 4.3 and Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JC_OM&A Programs
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	N/A, as BHI has more than 30k customers
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.	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JC_OM&A Programs
30	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-JB_OM&A_Cost_Drivers
31	Identification of change in OM&A in test year in relation to change in capitalized overhead	Exhibit 4, Section 4.2
OM&A Variance Analysis		
31	Re: 2-JC or 2-JD - variance analysis between: -Test Year vs Historical OEB approved -Historical OEB-Approved vs Historical Actuals (for the most recent historical OEB-approved year) -Test Year vs most recent Historical Actuals	Exhibit 4, Section 4.3
31	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	Exhibit 4, Section 4.3
31	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	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-K_Employee Costs
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.	N/A, as BHI more than three employees in any category
31	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit 4, Sections 4.3.1.1 and 4.3.1.2
31&32	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 4.3.1.4
32	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, Sections 4.3.1.3 and 4.3.1.5
32	Most recent actuarial report; tax section of evidence agrees with this analysis	Exhibit 4, Appendix A & B
32	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	N/A, as BHI is not a virtual distributor
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 4.3.1.5 and Appendix A & B
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
33	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit 4, Section 4.3.2.2
33	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, Sections 4.3.2.2 and 4.3.2.3
33	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-N_Corp_Cost_Allocation
33	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit 4, Section 4.3.2.6
33	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit 4, Section 4.3.2.7
Non-Affiliate Services, Regulatory One-Time Costs		
33&34	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit 4, Section 4.3.3 and Appendix C
34	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	N/A - Exhibit 4, Section 4.3.3
34	Information supporting the incremental costs associated with the preparation and review of the current appication	Exhibit 4, Section 4.3.4
34	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

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34	Completed Appendix 2-M, ongoing regulatory costs be included in the administration cost of Operations, Maintenance&Administration (OM&A) expense and material change be reported in Appendix 2-JB OM&A Cost Drivers.	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-M_Regulatory_Costs
LEAP, Charitable and Political Donations		
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 4.3.5
35	For any charitable contributions claimed for recovery, detailed information provided	N/A - Exhibit 4, Section 4.3.6
35	Confirmation that no political contributions have been included for recovery	Exhibit 4, Section 4.3.6
Cost of Non-Wires Solution and Conservation and Demand Management		
36	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 4.4.0
36	Distributor should generally not include any forecast costs associated with partnership in the IESO's Local Initiative Program (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	N/A - Exhibit 4, Section 4.4.0
Funding Options for Non-Wires Solutions		
36	If NWSs included in COS where NWSs expected to come into service during Price Cap IR term, identification of if costs of such NWSs included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future NWSs.	N/A - Exhibit 4, Section 4.4.1
36	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	N/A - Exhibit 4, Section 4.4.1
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
37	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 5.0
37	Completed Appendix 2-OA for last OEB approved and test years	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-OA Capital Structure
37	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-OB_Debt Instruments
37	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, Sections 5.2
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
38	Calculation of cost for each capital component	Exhibit 5, Section 5.2
38	Profit or loss on redemption of debt, if applicable	N/A - Exhibit 5, Section 5.2.4.7
38	Copies of current promissory notes or other debt arrangements with affiliates	Exhibit 5, Appendix A
38	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 5.2.3 and 5.2.4
38	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 5.2.4
38	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	N/A, as BHI has used rate consistent with the OEB guidelines
38	Historical return on equity achieved	Exhibit 5, Section 5.2.7
38	Overview of financing strategy	Exhibit 5, Section 5.2.8
Not-for-Profit Corporations		
38	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	N/A - Exhibit 5, Section 5.3
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	N/A - Exhibit 5, Section 5.3
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	N/A - Exhibit 5, Section 5.3
39	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	N/A - Exhibit 5, Section 5.3
39	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	N/A - Exhibit 5, Section 5.3
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
39	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 6.1
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 6.1.6
40	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit 6, Section 6.1.7
40	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	Exhibit 6, Section 6.1.8
Revenue Requirement Work Form		

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40	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Attachment7_2025_RRWF_BHI_04162025
40	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	N/A, as BHI has filed RRWF
40&41	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 6.1.9 and Attachment7_2025_RRWF_BHI_04162025
Income Tax or PILs		
41	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.	Attachment8_2026_PILS_Workform_BHI_04162025
41	Supporting schedules and calculations identifying reconciling items	Exhibit 6, Section 6.2.1
41	Most recent federal and provincial tax returns	Attachment9_2023 Federal and Provincial Tax Returns_BHI_04162025
41	Financial Statements included with tax returns if different from those filed with application	Attachment9_2023 Federal and Provincial Tax Returns_BHI_04162025
41	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	Exhibit 6, Section 6.2.1.3
42	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit 6, Section 6.2.1.4
42	Completion of the integrity checks in the PILs Model	Exhibit 6, Section 6.2.1.5
42	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 in Excel format	Exhibit 6, Section 6.2.1.6 and Exhibit 9, Section 9.1.5
42&43	May propose a mechanism to smooth the tax impacts over the five-year IRM term.	N/A - Exhibit 6, Section 6.2.1.6
Other Taxes		
43	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.	N/A - Exhibit 6, Section 6.2.2
Non-recoverable and Disallowed Expenses		
43	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit 6, Section 6.2.3
Other Revenue		
43	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-H_Other_Oper_Rev
43&44	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, Sections 6.3.1, 6.3.2, 6.3.3 and 6.3.4
44	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 6.3.4
44	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
44	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 6.3.4
44	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	N/A - Exhibit 6, Section 6.3.4
44	Revenues or costs (including interest) associated with deferral and variance accounts not included in other revenues.	Exhibit 6, Section 6.3.4
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
45	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	Attachment10_2026_Cost_Allocation_Model_v1.0_BHI_04162025 and Attachment7_2025_RRWF_BHI_04162025
45	Description of weighting factors, rationale for use of default values (if applicable)	Exhibit 7, Section 7.1.1.2
45	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	N/A - Exhibit 7, Section 7.1.1.2
45&46	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.	Attachment10_2026_Cost_Allocation_Model_v1.0_BHI_04162025
Load Profiles and Demand Allocators		
46	Update all classes' load profiles and update demand allocators	Exhibit 7, Section 7.1.1
46	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Exhibit 7, Section 7.1.1
46	If multivariate regression model is used, the following provided: -statistics and statistical tests related to regression equation(s) coefficients and intercept, results of tests for autocorrelation and multicollinearity -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the source of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	Exhibit 7, Section 7.1.1
47	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)	Exhibit 7, Section 7.1.1 and Attachment11_Load_Profile_Derivation_BHI_04162025
47	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 and Attachment11_Load_Profile_Derivation_BHI_04162025

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47	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
47&48	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	N/A, as BHI is not an embedded Dx
48	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	N/A - Exhibit 7, Section 7.1.2.4
49	Standby Rates - distributors with interim standby rates to request approval for final standby rates and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks to establish new standby rates or seeks chaneges to it's 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
49	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	N/A - Exhibit 7, Section 7.1.3
49	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	N/A - Exhibit 7, Section 7.1.4
Class Revenue Requirements		
50	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		
50&51	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
51	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	N/A - Exhibit 7, Section 7.3
51	If Cost Allocation Model other than OEB model used - exclude LV and exclude DVA balances and that revenues exclude rate riders, rate adders and the Smart Metering Entity Charge. Distributor must also ensure that information relevant to customer charge unit costs, microFIT unit costs and revenue is consistent with the output from the OEB's model	N/A - Exhibit 7, Section 7.1
EXHIBIT 8 - RATE DESIGN		
51	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, Section 8.1.3
Fixed Variable Proportion		
51&52	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		
52	Completed RTSR Model in Excel	Attachment12_2026_RTSR_Workform_BHI_04162025
52	RTSR information consistent with working capital allowance calculation; explanation for any differences	Exhibit 8, Section 8.2
Retail Service Charges		
52	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		
53	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	N/A - Exhibit 8, Section 8.4
Specific Service Charges		
53	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	N/A - Exhibit 8, Section 8.5
53	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	N/A - Exhibit 8, Section 8.5
53	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	N/A - Exhibit 8, Section 8.5
54	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	N/A - Exhibit 8, Section 8.5
54	Revenue from SSCs corresponds with Operating Revenue evidence	Exhibit 8, Section 8.5
Wireline Pole Attachment Charge		

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54	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 pole attachment charge will be established by order without a hearing. A distributor is required to update the charge as per that order.	Exhibit 8, Section 8.5.1
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
55	Forecast LV Cost	N/A - Exhibit 8, Section 8.6
55	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	N/A - Exhibit 8, Section 8.6
55	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	N/A - Exhibit 8, Section 8.6
55	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	N/A - Exhibit 8, Section 8.6
55	Proposed LV rates by customer class	N/A - Exhibit 8, Section 8.6
Smart Meter Entity Charge		
55	Current OEB-approved smart metering charge (SMC) until the OEB approves 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
56	Statement as to whether LDC is embedded including whether fully or partially	Exhibit 8, Section 8.8
56	Study of losses if required by previous decision	Exhibit 8, Section 8.8
56	3-5 years of historical loss factor data - Completed Appendix 2-R	Attachment1_OEB_Chapter2Appendices_BHI_04162025, App.2-R_Loss Factors
56	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	N/A - Exhibit 8, Section 8.8
56	Explanation of SFLF if not standard	Exhibit 8, Section 8.8
56	Reconciliation between the application and RRR filing	Exhibit 8, Section 8.8
Tariff of Rates and Charges		
56	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 A & B and Attachment14_Excel_Current_Tariff_Sheet_BHI_04162025
56	Completed Bill Impacts Model	Attachment13_Tariff_Schedule_and_Bill_Impact_Model_BHI_04162025
56	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	N/A - Exhibit 8, Section 8.9
56	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Exhibit 8, Section 8.4
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
57	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	Attachment7_2025_RRWF_BHI_04162025
Bill Impact Information		
57	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)	Attachment13_Tariff_Schedule_and_Bill_Impact_Model_BHI_04162025
57	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 and Attachment13_Tariff_Schedule_and_Bill_Impact_Model_BHI_04162025
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
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	Exhibit 8, Section 8.11
Rate Mitigation		
58	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.	N/A - 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	N/A - Exhibit 8, Section 8.13
58	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	N/A - Exhibit 8, Section 8.13
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	N/A - Exhibit 8, Section 8.13
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	N/A - Exhibit 8, Section 8.13
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
58&59	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 9.0.1

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59	In a separate section under the summary table: - For any account identified in the summary table as not being proposed for disposition, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified in the summary table that are proposed to be discontinued, provide an explanation as to why it is being discontinued	Exhibit 9, Sections 9.01, 9.0.2 and 9.0.3
59	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	N/A - Exhibit 9, Section 9.0.4
59	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.	Attachment15_DVA_Continuity_Schedule_BHI_04162025
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 9.0.6
59&60	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 9.0.7
60	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 9.0.8
Disposition of Deferral and Variance Accounts		
60	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	Attachment15_DVA_Continuity_Schedule_BHI_04162025
60	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 9.1.0, pg. 20
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, Sections 9.1.0.1 and 9.1.0.2
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 9.1.0.2
Disposition of Accounts 1588 and 1589		
61	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	N/A - Exhibit 9, Section 9.1.1
61	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
61	If requesting final disposition of balances for the first time following implementation of the accounting guidance, confirmation that accounting guidance has been implemented fully effective January 1, 2019	N/A - Exhibit 9, Section 9.1.1
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
61	Commodity Accounts Analysis Workform (Formerly 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 balance that was previously approved on an interim basis, the Commodity Account Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589	Attachment16_2026_CAA_Workform_BHI_04162025
61	As described in Note 5 in the Commodity Accounts 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
62	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the Commodity Accounts Analysis Workform.	Exhibit 9, Section 9.1.1.2 and Attachment16_2026_CAA_Workform_BHI_04162025
Disposition of Account 1580, Sub-account CBR Class B Variance		
62	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
63	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	N/A - Exhibit 9, Section 9.1.3
Disposition of Retail Service Charges Related Accounts		
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	N/A, BHI does not have balance in these accounts
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	N/A, as BHI does not have these acounts
63&64	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	N/A, as BHI does not have these acounts
Disposition of Account 1592, Sub-account CCA Changes		
64	Provide full revenue requirement impact recorded in Account 1592, Sub-account CCA Changes and the balance sought for review and disposition	Exhibit 9, Section 9.1.5
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

2026 Cost of Service Checklist
Burlington Hydro Inc.
EB-2025-0051

Date: April 16, 2025

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
64	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	N/A, as BHI does not have Account 1592 amounts related to ICM/ACM
64	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	Attachment15_DVA_Continuity_Schedule_BHI_04162025
64	If a distributor does not have a balance in this sub-account, the distributor must explain why	Exhibit 9, Section 9.1.5
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		
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		
66	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
66&67	Distributors requesting disposition of any amounts recorded in the GOCA Variance Account are to file, at a minimum, the following information: -A statement confirming that distributor has reflected the GOCA impact in the locate costs of the test year's revenue requirement - The proposed disposition of the GOCA Variance account under Account 1508 Sub-Account GOCA Variance Account and discontinuance of the account after the rebasing application - Rationale needs to be provided if the distributor proposes to continue the GOCA Variance account in the rate term	N/A, as BHI does not have a GOCA Variance Account
Disposition of Account 1511 Incremental Cloud Computing Implementation Costs		
67	Distributors requesting disposition of any amounts recorded in the Cloud Computing Implementation Account are to file, at a minimum, the following information: -A discussion and supporting explanation for the annual amounts recorded in the account, including the methodology used to measure incremental costs and offsetting savings, as applicable. If there are no offsetting savings, explanation should be provided - A list of the cloud solution(s), actualor forecast amount(s), type(s) of expenditure, adn nature of costs -A list of costs requested by projects (each with the business purpose of the projects) and a statement for each project regarding whether the cost associated for each project is material -A discussion of whether the distributor would be able to reasonably forecase any futher entries in the account, up to the effective data of 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) - A statement confirming that the distributor proposes discontinuation of the Cloud Computing Implementation Account, effective the same date as the new rates	Exhibit 9, Section 9.1.8
Disposition of Distributor-Specific Accounts		
68	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, Sections 9.1.9 to 9.1.15
Establishment of New Deferral and Variance Accounts		
68	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	N/A - Exhibit 9, Section 9.2
Lost Revenue Adjustment Mechanism Variance Account		
69	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 9.3.1
Disposition of LRAMVA		
69	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds, if possible	Exhibit 9, Section 9.3.1
Distributors with zero balance in the LRAMVA (including those with LRAM-eligible amounts previously approved on a prospective basis):		
70	Indicate this fact in its application and advise that it is not requesting any disposition	Exhibit 9, Section 9.3.1
Distributors with non-zero balance in the LRAMVA:		
70	A distributor that does not have a confirmed zero balance in the LRAMVA should seek disposition as part of its application, with supporting information, or provide a rationale for not doing so.	Exhibit 9, Section 9.3.1
Continuing Use of the LRAMVA for New NWS Acitivities		

2026 Cost of Service Checklist

Burlington Hydro Inc.

EB-2025-0051

Date: April 16, 2025

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
70	Indication of whether distributor is requesting an LRAMVA for one or more activities related to distribution rate-funded NWS activities or LIP activities if this request has not been addressed in a previous application	Exhibit 9, Section 9.3.2
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	N/A - Exhibit 2, Section 2.10
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	N/A - Exhibit 2, Section 2.10

Appendix B – BHI 2025 Business Plan

Burlington hydro inc.

NOVEMBER 2024

BHI 2025 Business Plan

Confidential

Table of Contents

Burlington hydro inc.

Part A
Business Overview

Executive Summary

The purpose of Burlington Hydro Inc.'s (BHI's) business plan is to provide a forward-looking roadmap that aligns our energy delivery and service commitments with the evolving needs of our customers and stakeholders. This plan outlines our strategy to enhance operational effectiveness, adapt to the energy sector's rapidly changing landscape, and prioritize customer and stakeholder engagement while ensuring value, reliability and resilience in our services and operations.

The strategic priorities and initiatives for 2025 and 2026 include:

- Provide exceptional internal and external customer service across the organization.
- Deliver electricity safely and reliably by renewing deteriorated components of the system most at risk of failure.
- Provide comprehensive public safety awareness education/communications and maintain a culture that prioritizes safety for employees and customers.
- Upgrade the distribution system by hardening the grid to respond to increasing extreme weather events.
- Enhance support for Distributed Energy Resources (DERs) integration and electric vehicle (EV) infrastructure to support a sustainable energy transition.
- Respond to and prepare for increased demand and customer growth in specific areas of our service territory.
- Continuous investment in technology that helps reduce electricity distribution costs, provides consumer choice and creates business value.
- Invest in workforce planning and training programs to equip employees with skills for a digital environment. Focus on talent acquisition, development, and retention to build a future ready workforce.
- Deliver electricity at prudent and value-based distribution rates.

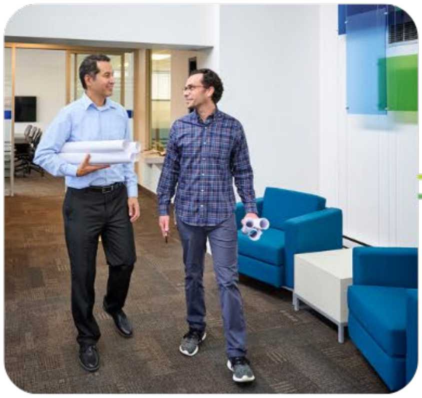
The Ontario energy landscape that BHI operates in is undergoing transformational change driven by growth, electrification, technological advancements, policy and regulatory shifts, and evolving consumer expectations. These changes create both challenges and opportunities for BHI and the broader industry. The importance of, and public focus on, sustainability, resilience, and reliability, especially in light of climate change, increases the pressure on BHI to be proactive in its planning. To meet future demands, BHI must ensure it has the capacity to innovate while maintaining and hardening its grid. Inadequate planning could lead to delays in grid modernization, service interruptions, and an inability to meet regulatory and government net-zero targets.

These challenges and opportunities are compounded by anticipated housing growth and the need to replace aging distribution infrastructure. Additionally, evolving customer expectations now expect more personalized, seamless, and responsive service experiences, as well as options for energy efficiency and DER choices. This will require new roles focused on customer service and internal support.

BHI conducts extensive customer engagement with customers to understand customer priorities and expectations. Insights gained include:

- A strong interest in sustainability and renewable energy choices.
- A need for enhanced communication, especially during outages or service changes.
- Desire for greater transparency on service costs and energy options.
- Customers are aligned with BHI's strategic priorities of providing safe and reliable electricity at prudent rates.
- Customers place value on proactively replacing deteriorated infrastructure, upgrading the distribution system to respond to increasing extreme weather, and investing in new and innovative technology to modernize the grid.

Through this business plan, BHI is committed to fostering a customer-centric approach, emphasizing value, reliability, and innovative approaches to enhance its operations and prepare for the energy transition. This plan will ensure that BHI remains a leader in delivering safe, efficient, resilient and reliable energy solutions.



Company Overview

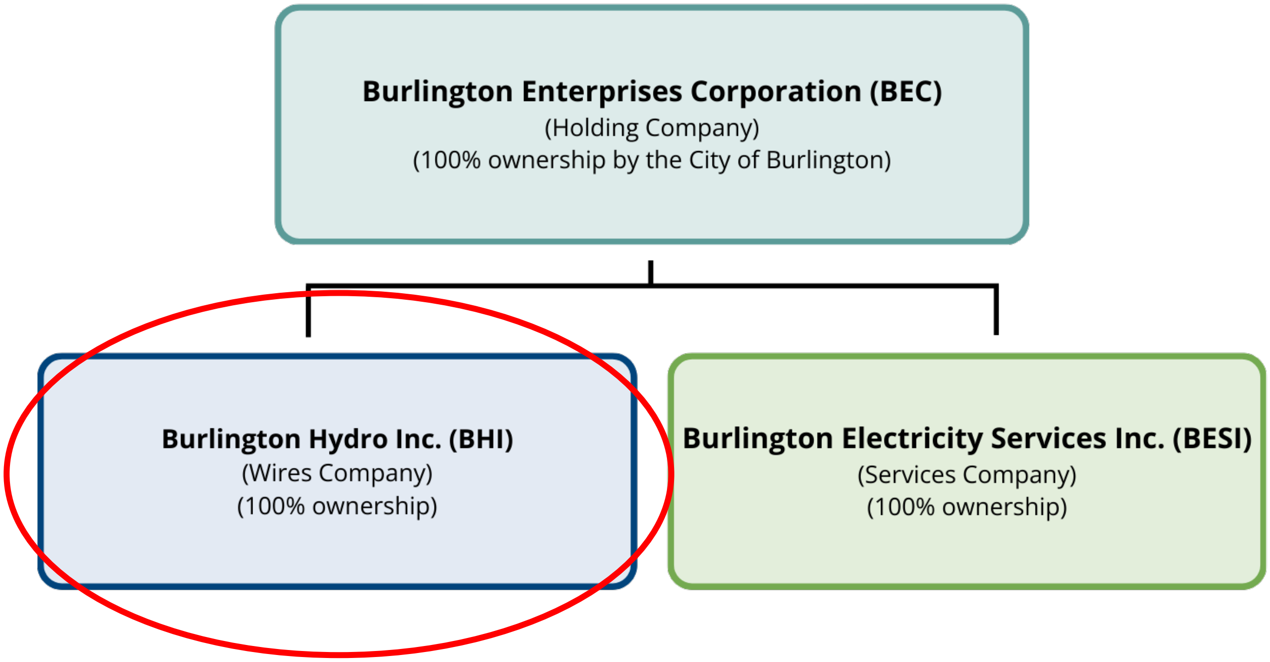
History and Corporate Structure

Established in 1945, Burlington Hydro is an energy services and local distribution company (LDC) in the Ontario electricity distribution market, serving the City of Burlington. Serving approximately 69,000 residential and commercial customers consisting of Residential, General Service, Street Light, and Unmetered Scattered Load customers/connections. With a total licensed service area of 188 square kilometres, Burlington Hydro operates 32 substations and maintains 1,600 kilometers of medium voltage distribution lines to ensure reliable electricity delivery.

Following changes to the *Electricity Act* and the introduction of the *Energy Competition Act* in 1998, Burlington Hydro was established as a private corporation. Formally, Burlington Hydro had operated in a not-for-profit capacity as a hydro-electric commission (HEC) with powers laid out under the Public Utilities Act and the Power Corporation Act.

Burlington Hydro was incorporated and wholly transferred into the ownership of the City of Burlington on January 1, 2000, as a for-profit company. At that time, the City created a holding company, Burlington Hydro Electric Inc., to oversee two subsidiary companies: a regulated "wires" company, Burlington Hydro Inc., and an unregulated company, Burlington Electricity Services Inc.

Burlington Hydro Electric Inc. (BHEI) was re-structured and renamed Burlington Enterprises Corporation (BEC) in 2019, to align with best practices in utility governance.



Purpose Statement

Today's reliable energy partner for tomorrow's innovative community.

We serve the residents and businesses of Burlington with reliable energy, committing to exceptional customer service and empowering customers through valuable tools and resources.

At Burlington Hydro, we are set apart by our unwavering focus on operational effectiveness and our dedication to safety and customer service. This commitment enables our customers to concentrate on what matters — keeping life moving and our community thriving.

Mission

To provide reliable, efficient, and safe energy solutions to the community.

Vision

To be recognized as a leading energy solutions provider and customer-focused LDC.

Core Values

Burlington Hydro Cares for People
We interact with customers, employees, the public, and our business partners with integrity and respect, and at all times act in a safe, responsible and professional manner.

Burlington Hydro Cares for the Community
We take pride in making significant contributions to our community by supporting local business development activities and delivering important safety programs to our schools. We are committed to supplying our community with electricity for the long term.

Burlington Hydro Cares about Stewardship
We value the long-term health and sustainability of Burlington Hydro and will ensure availability of a future electricity supply that meets customer needs and growth. We value the community we serve and the environment in which we operate, managing risks to eliminate or minimize adverse impacts associated with our businesses.

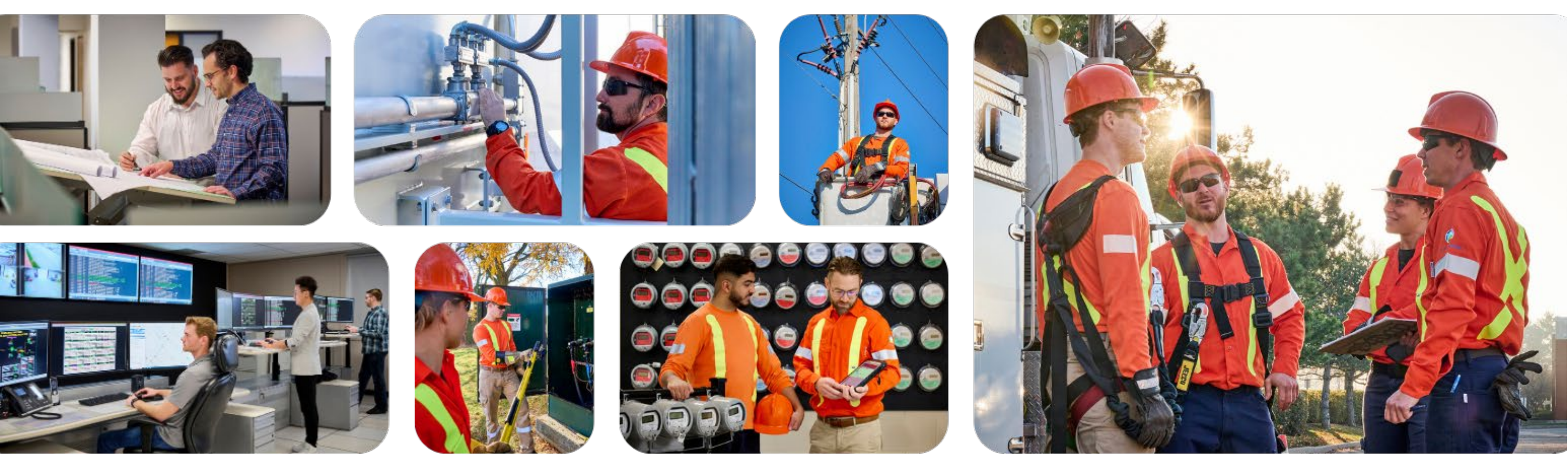
Burlington Hydro Cares about Performance
We value a balanced, sustainable business model. We deliver superior products to our customers in a safe and efficient manner, striving for excellence and continuous improvement in all aspects of our business.

Overview of Core Business Functions

Operations & Engineering

BHI has secured enough capacity with its new Transformer Station (TS) to accommodate the City's target of an additional 100,000 people (over the next 20 to 30 years), along with a managed strategy for the move to electrification. Operations & Engineering departments are essential to planning, building, and maintaining a safe, resilient, and reliable distribution network.

- **Engineering:** BHI's engineering department is central to designing and planning Burlington's power distribution system, managing both overhead and underground infrastructure. As BHI anticipates the impacts of the energy transition, emerging technologies, and digitalization, the engineering department has realigned into three key functional areas:
    - Customer Connections and Key Accounts
    - System Planning and Asset Management
    - Capital Projects and Energy Transition
- **Powerlines:** The Lines crews are on the front lines of service and maintenance. They install new poles, transformers, wires, and customer connections while maintaining safe and reliable service through ongoing infrastructure upgrades and emergency response.
- **Stations:** Responsible for maintaining 32 municipal stations within BHI's service territory, the Stations team conducts tests on suspect cables, locates faults on primary cables, installs smart switches and supports emergency response.
- **Metering:** The Metering team maintains approximately 69,000 meters within BHI's service area and investigates power quality issues. The team also supports ongoing upgrades to support next-generation metering and provide enhanced tools for improved service and data accuracy. This team also supports emergency response and frontline response to customer trouble calls.
- **Control Room:** Acting as the overarching 'controlling authority' for the Electrical Distribution Network, the Control Room is responsible for authorizing and documenting all work conducted on the network. This team ensures operational safety and system integrity, managing real-time responses to maintain a secure and reliable distribution network.



Finance

Finance encompasses several critical departments responsible for safeguarding financial resilience, ensuring regulatory compliance, and supporting efficient operations and strategic growth. Collectively, these departments—Regulatory Affairs, Conservation and Demand Management, Billing, Supply Chain, Capital Planning, and Accounting and Financial Reporting—work together to reinforce BHI's commitment to customers, continuous improvement, and sustainable growth.

Key priorities across these departments include:

- **Regulatory Affairs:** Managing rate-setting, regulatory filings, Cost of Service applications, and policy review/implementation, Regulatory Affairs ensures alignment with regulatory standards while balancing customer affordability and long-term operational needs.
- **Conservation and Demand Management:** With Ontario's new conservation and demand management (CDM) framework launching in 2025, the focus will be on implementing energy efficiency programs that support sustainability goals for both customers and the broader grid.
- **Billing:** Responsible for billing residential, small commercial, and large commercial accounts, ensuring accuracy and clarity in invoicing while offering customers access to helpful programs and resources.
- **Supply Chain:** Amid ongoing price and lead-time volatility for essential materials and services, supply chain priorities include cost containment, purchasing and contract management, closely monitoring inventory, adapting re-order practices, and exploring alternative suppliers. These efforts ensure access to key materials and mitigation of cost increases on labor-intensive services like powerline technician services, tree trimming and utility locates.
- **Capital Planning:** In alignment with the Distribution System Plan (DSP), capital planning efforts are concentrated on creating and monitoring the overall budget for infrastructure investments that address reliability, electrification, and sustainable growth for Burlington's community.
- **Accounting and Financial Reporting:** Responsibilities include overseeing the budgeting process, managing accounts payable/receivable, cash flow management, debt service and credit use, and refining processes to ensure accurate, timely financial reporting. Regular financial analysis provides leadership with insights for strategic, informed decision-making.

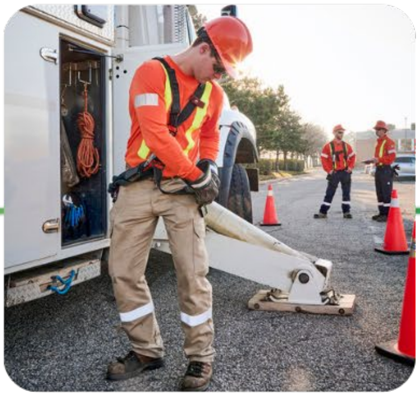
Human Resources

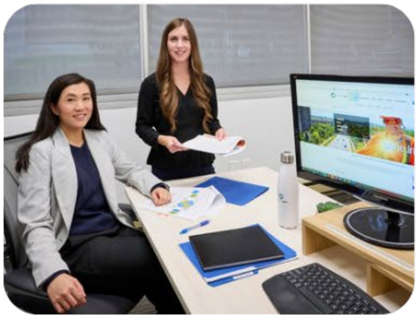
Human Resources (HR) at BHI is committed to building a supportive, high-performance workforce through a People Strategy that positions BHI as a top employer within the utility sector. This strategy aligns HR practices with BHI's strategic goals and addresses critical areas such as:

- Strategic Talent Acquisition & Recruitment
- Workforce Readiness
- Employee Retention & Development

BHI aligns its HR team and leadership competencies to execute these objectives which includes:

- Supporting business continuity and sustainable people practices
- Managing talent through a strategic lens
- Supporting meaningful employee engagement efforts and managing turnover
- Driving succession planning for frontline leaders, aligned with leadership competencies
- Promoting organizational culture and enhancing employee engagement
- Reducing recruitment and retention costs by utilizing competency-based processes
- Strengthening the talent brand to reinforce BHI as a Top Employer
- Supporting meaningful career development and talent mapping





Health & Safety

The Health & Safety (H&S) department drives BHI's commitment to a strong safety culture, guided by the company's Five-Year Health and Safety Strategic Plan ('Safety Plan') and the Health, Safety, and Environment Management System (HSEMS). These frameworks support a proactive approach to risk mitigation and continuous improvement in workplace safety. The Safety Plan focuses on preparing for the future by:

- Adopting more progressive safety systems and technology to enhance automation and digitization to reduce manual involvement.
- Leveraging a strong safety culture during times of rapid change in technology and demographics.
- Integrating accountability for safety across all levels of the organization.
- Adding effective leading indicators.
- Supporting employee mental health and wellbeing.

BHI fosters a safety-first environment by empowering employees to participate actively in H&S initiatives, with managers and supervisors leading by example. Additionally, the department continuously assesses best practices to advance beyond the Workplace Safety and Insurance Board's (WSIB) Safety Excellence standards.

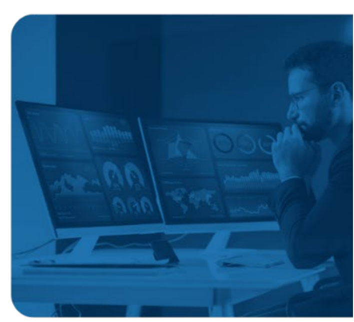
Information Technology

The Information Technology (IT) department plays a crucial role in supporting the organization's strategic objectives through technology investments, cybersecurity initiatives, and system integration. To align with Burlington Hydro's strategic direction, the IT department is undergoing a realignment, establishing an enhanced governance framework that promotes decentralized empowerment under a unified IT umbrella. This realignment is expected to deliver:

- Enhanced organizational and operational efficiencies
- Improved alignment across departments
- Strengthened cybersecurity measures

BHI's technology principles have evolved over the last few years to align more closely with organizational objectives and the changing technology landscape within the industry, to guide key technology related investments including:

- Ensuring Information, Technology and Security Services investments are focused on emerging trends and grid modernization.
- Continuous Enterprise-Wide Integration of Information, Operation and Internet of Things Technology.
- Strategic deployment of information and operation technology services.
- Continuous engagement with GridSmartCity for shared services and knowledge.
- Continuous improvement in evolving technology related skill sets.
- Managing effective IT governance for enterprise technology needs, including products and services delivery.



- Delivering meaningful Data Analytics, Business Intelligence and Predictive Analysis to assist the organization to meet its strategic goals.
- Value driven digitization and automation of business processes and documentation.
- Continuous fostering of Key Stakeholder relationships including customers, 3rd party contractors, vendors and key industry partners.

Corporate Communications and Customer Service/Engagement

The Communications department at Burlington Hydro manages the company's brand and public relations, fostering trust and engagement among customers, stakeholders, and the community. BHI closely monitors and strives to deliver on the following communication priorities:

- Bring together various elements/touch points the company makes with its customers/stakeholders and ensure a consistent 'value proposition' message.
- Engender trust and confidence across all stakeholder and customer audiences, by instilling the integral role we play in the growth and prosperity of our community. A reimagined engagement approach will ensure proactive communication, marketing and responsiveness to evolving customer and stakeholder needs and expectations.
- Extol the virtues of the value of electricity in our everyday lives – at home, at work and at play.
- Engage all classes of customers and provide practical examples and success stories of how we deliver value back to our customer, and through to the community.

The Customer Service team serves as the frontline and first impression for Burlington Hydro, ensuring reliable and responsive service across all customer interactions. In 2023, Customer Service received 43,732 calls and 14,770 emails underscoring its essential role in delivering high-quality support and fostering positive customer relationships.

Burlington Hydro's commitment to customer satisfaction is reflected in its proactive approach to addressing customer inquiries, providing program information, and assisting with account management. In 2023, BHI achieved a 90% overall customer satisfaction rating in its annual Customer Satisfaction Survey, conducted each fall. In 2025, our focus will be to enhance customer service framework and processes in order to provide exceptional customer service across the organization, ensuring customers feel informed and supported.

Strategic Framework

Industry Trends and Regulatory Landscape

The Ministry of Energy and Electrification (MoE&E) has outlined a clear vision for the energy transition in Ontario, emphasizing the need to leverage the province's clean energy grid to drive electrification and job creation, while continuously improving reliability, resiliency, and customer choice. As the economy decarbonizes, electricity demand is expected to grow significantly. In addition to the energy transition, other key trends and factors shaping the business environment include:

- **Net Zero Economy (Energy Transition and Electrification):** Canada has an economy-wide goal by 2050, and net zero electricity system and EV adoption by 2035 requires significant changes, including investments in green technologies and infrastructure. Ontario's transition toward a low-carbon economy is driving significant changes in energy demand and has catalyzed a movement towards grid modernization, EV adoption, and DERintegration.

- **Climate Change** – the impetus for energy transition is climate risk. Increased weather events are increasing in frequency and magnitude. The City of Burlington has created a Climate Action Plan and expects to be net zero by 2050, in alignment with Canada's economy wide goal. BHI must prepare to support and enable these goals in addition to incorporating the necessary system capacity.

- **Growth**: The Independent Electricity System Operator (IESO) forecasts that electricity demand will increase by 75 percent by 2050. This growth will be driven primarily by economic growth, continued increases in Ontario's population, mining and steel industry electrification, and through Ontario's success in attracting unprecedented investment in Ontario's industrial base, including the electric vehicle supply chain. Housing and employment growth, including Ontario's plan to build 1.5 million homes and Burlington's 29,000 new units by 2031, all of which is primarily vertical builds, will significantly impact electricity demand, infrastructure capacity, and customer service needs.

  The MoE&E plans to introduce legislation that, if passed, will support the construction of new homes and businesses by making it easier and more affordable to make the "last mile" connections. Changes, identified in the Ontario Energy Board's (OEB) *Report Back to the Minister on System Expansion for Housing Development,* include extending the revenue horizon for connecting residential developments from 25 years up to 40 years and establishing a new Capacity Allocation Model that considers multi-customer, multi-year projects. While promoting growth, these changes could increase the upfront amount that distributors pay towards expansion projects.

- **Digitalization, New Technologies and Cyber Security:** There is a need for rapid advancement of technology to meet new customer and employee demands. Adding significantly more Distribution Energy Resources that will integrate into BHI's infrastructure while at the same time AI accelerating digitalization, will introduce increased cyber risk.

- **Change in Customer Preferences:** Customer preferences are shifting towards faster, digital services, such as EV connections, real-time billing options, and energy efficiency solutions. Residential customers expect faster connections for EVs and digital services. Commercial customers want more energy options to improve efficiencies and meet their own sustainability goals.

- **Competitive Labour Market:** The electricity sector faces challenges in attracting and retaining talent. With an aging workforce and expected growth in the sector, the Electricity Human Resources Canada (EHRC) predicts the need for 28,000 new employees by 2030, a 25% workforce increase. Investments in talent development through upskilling and extending IT capabilities are critical for sustaining future growth.

- **Shifting Regulatory Requirements**: The Ontario electrical industry is heavily regulated, and consists of several agencies and companies including: the government, namely the MoE&E, who sets overall policy for the energy sector regulators such as the OEB, who regulates the rates, activities and defines performance standards of Ontario's LDCs; and the Independent Electrical System Operator (IESO) who manages the power system in real-time, plans for the province's future energy needs and enables conservation. Some of the pertinent regulations and vision papers that are impacting our industry and BHI are highlighted below.

  In October 2024, the MoE&E released *Ontario's Affordable Energy Future: The Pressing Case for More Power*, outlining a vision for a clean, reliable, and affordable energy system to support Ontario's growth. The 2025 integrated energy plan will focus on grid modernization, resilience, energy efficiency, and consumer engagement. Read this vision paper here.

  The OEB is tasked with implementing the MoE&E direction to review electricity infrastructure costs and enhance the electricity distribution system. Priorities include supporting housing, transportation, and job creation through system expansion and facilitating innovation in DERs and local energy programs.

  The OEB's ongoing focus on **Distribution Sector Resiliency, Responsiveness, and Cost Efficiency** includes incorporating climate resilience into investment planning, ensuring that systems can handle increased severe weather events, and enhancing communication strategies during outages. In relation to this, the OEB launched its **Vulnerability Assessment and System Hardening (VASH)** project in June 2024 which may result in new directives to distributors, and methodologies to contemplate and test vulnerability, resilience and storm hardening.

  The OEB has launched a study to assess the need, value, functionalities, opportunities, risks, incumbent and sector roles, and impact of potential **Distribution System Operator (DSO)** models for Ontario. A DSO is an entity with advanced capabilities to integrate, manage and optimize DERs for distribution and transmission services.

  The OEB is undertaking a generic proceeding to consider the methodology for determining the values of the **Cost of Capital Parameters** (debt rates and return on equity) and deemed capital structure to be used to set rates, the results of which could affect the rates that BHI is permitted to charge its customers in 2026 and beyond.

The OEB is conducting a consultation to advance its **Performance-based Approach to Rate Regulation**. The objective of this initiative is to develop ways to strengthen the link between what electricity distributors earn and the achievement of outcomes consumers value, such as cost-effectiveness, reliability and customer service. The OEB will be focused on assessing the cost effectiveness of remunerating utilities based on traditional capital infrastructure deployment.

IESO Market Renewal Program (MRP) – In addition to the Pathways to Decarbonization paper issued in 2022, the IESO is implementing its Market Renewal Program (MRP), expected to go live May 1, 2025. This initiative will improve the way electricity is supplied, scheduled, and priced by introducing a day-ahead market, enhanced unit commitment, and locational pricing. These changes are intended to make the electricity market more efficient and integrate emerging technologies like DERs, storage, and hybrids.

Energizing Partnerships

GridSmartCity Cooperative

The GridSmartCity Cooperative's (GSCC) 16-member LDCs pursue efficiencies and service improvements, the same as incorporated companies, but with the advantage of pooling member knowledge and resources. The structure of the Cooperative is ideally suited to help Burlington Hydro and member LDCs adapt, prepare, and build by:

- Pursuing contracts that further cost savings/cost avoidance for LDC partners
- Championing innovation by pursuing emerging technologies
- Balancing distributed energy resource benefits with implementation complexity and cost
- Protecting and improving electricity reliability through the convergence of electric vehicles
- Helping deal with the broadening cyber security landscape
- Continuing to be a strong forum for collaboration and best practice sharing

BHI is working with GSCC for third party, supply chain and vendor risk management as part of the requirements of the Ontario Cyber Security Framework (OCSF). This engagement is focused on areas related to information system controls effectiveness, cyber threat intelligence, asset vulnerabilities, incident response plans and overall security posture assessment as part of third party and supply chain risk evaluation.

In addition, GSCC has commissioned two studies to assist partners with future technology changes:

1. A study to determine the technological, operational and financial requirements to implement a DSO model.
2. A Next Generation Metering Strategy Scoping exercise as next-generation smart meters are pivotal for the grid's evolution, offering enhanced data capabilities that enable grid-edge enablement. These meters empower utilities to monitor and manage energy flows at the network's edge in real-time, optimizing grid operations and enhancing reliability.

Electricity Distributors Association (EDA)

The Electricity Distributors Association (EDA) is the voice of Ontario's LDCs, advocating for policy and regulatory outcomes that support the needs of the province's electricity customers and utility sector. Through its work, the EDA provides BHI with valuable resources, industry insights, and a platform for influencing policies that shape Ontario's energy future. The association offers services such as regulatory guidance, industry representation, and the opportunity to share knowledge and best practices across its membership.

The EDA's recent Vision Paper: Solving Grid-Lock underscores the pivotal role of LDCs in supporting Ontario's energy transition, highlighting several key priorities:

- Promoting a shared vision for electrification to support Ontario's clean energy goals
- Investing in grid infrastructure to enhance readiness for increased electrification demands
- Advancing policy frameworks that empower utilities to deliver reliable and efficient services
- Focusing on grid modernization and resilience to minimize energy costs for customers, boost economic competitiveness, and ensure long-term sustainability

SWOT

STRENGTHS

- Reliable and Robust Distribution System
- Strong Brand and Local Presence
- Customer Centric Approach
- Customer Base
- Financial Stability
- Organizational Structure and Compliancy
- Employer of Choice and Skilled Workforce

WEAKNESSES

- Aging Infrastructure
- Limited Scale and Geographic Presence
- Workforce Renewal, Engagement and Upskilling Required
- Limited Innovation

OPPORTUNITIES

- The Energy Transition, Electrification and Renewable Energy
- Infrastructure and Grid Modernization
- Electric Vehicle Infrastructure
- Systems, Data Analytics and AI

THREATS

- Regulatory Changes and Uncertainty
- Cybersecurity Risks
- Climate Change and Natural Disasters
- Competitive Labour Market

Please see Appendix B for a more comprehensive SWOT analysis.

Objectives

Burlington Hydro's strategic objectives focus on delivering reliable service, operational excellence, and financial stability while fostering a positive workforce and adapting to the evolving needs of our customers.

2025/2026 Priorities

FINANCIAL STEWARDSHIP	INTERNAL PROCESSES AND OPERATIONAL EXCELLENCE	CUSTOMER AND COMMUNITY	LEARNING AND GROWTH
1.1 Responsible Financial Management: Optimize distribution rates and costs and mitigate financial risks while making prudent investments in technology, infrastructure, and operations.	**2.1 Reliability & Resilience:** Ensure safe, resilient, and reliable electricity distribution through proactive system maintenance and climate resilience initiatives.	**3.1 Customer Service:** Enhance customer service framework and processes to provide exceptional customer service across the organization, ensuring customers feel informed and supported.	**4.1 Workforce Planning & Development:** Optimize organizational structure, enhance succession planning, and provide ongoing training and development opportunities to ensure long-term talent sustainability and readiness.
1.2 Efficiencies: Find continued efficiencies and cost savings that deliver value to customers and shareholders.	**2.2 Efficiencies & Digitalization:** Enhance operational efficiency by leveraging digital tools to improve processes, automate tasks, and reduce costs.	**3.2 Customer Satisfaction & Engagement:** Enhance customer and stakeholder engagement and engage with customers regularly to gather feedback and improve services, ensuring their needs are met and their experience is positive.	**4.2 Employee Engagement & Culture:** Foster a positive, inclusive, and collaborative work environment that actively engages employees, promotes well-being, and aligns with company values.
1.3 Capital Planning: Develop and implement financial strategies to support capital investments in infrastructure, electrification, and growth.	**2.3 Electrification and Growth** Drive sustainable growth and support electrification by upgrading infrastructure and planning for increased growth and demand.	**3.3 Public Safety:** Strengthen public safety awareness through education, outreach, and proactive communication.	**4.3 Adaptation to Innovation:** Continue to adapt and integrate emerging skills and technologies such as data analytics and system integrations that enhance operations.
1.4 Regulatory Compliance: Ensure compliance with regulations and accounting standards to support long-term financial stability and ensure operational and financial integrity.	**2.4 Governance & Risk Management:** Continue to enhance governance and risk management programs, including strengthening cybersecurity measures.	**3.4 Communications & Branding:** Strengthen the company's brand and reputation through strategic communications, public relations efforts, and community engagement initiatives.	**4.4 Health & Safety:** Promote a strong safety, wellness and inclusivity culture by providing comprehensive safety training and encouraging employee involvement in health, safety, and wellness initiatives.

See Appendix C for expanded action plans.

Risk and Mitigation

BHI employs Enterprise Risk Management (ERM) to monitor and assess risk in eight broad categories as identified below. A risk matrix, updated and reported quarterly to the BHI Board, is used as a tool to assess risk by defining ranges for risk appetite, risk probability and impact scores.

- Operational
- Financial
- Profitability
- Reputational
- Compliance
- Regulatory
- Technology
- Strategic

Once identified, the business is managed to avoid risks that:

- Negatively affect the quality of service;
- Negatively affect the health and safety of employees and the public;
- Negatively affect the reputation of the corporation and its shareholder;
- Negatively affect the financial integrity of the corporation;
- Lead to laws, codes or regulations being breached; or
- Endanger the future viability or existence of the corporation.

The most significant risks currently facing BHI are:

- **Service Disruption:** The increased incidence of extreme weather events, unexpected equipment failures and supply chain challenges (pricing increases, longer lead times, limited supply) have the potential to disrupt service for longer durations and to be more frequent.

- **Employee Retention:** All LDCs including BHI are facing retention and resourcing challenges as a result of an aging workforce, a low unemployment rate and high demand for skilled labour.

- **Regulatory, Environmental and Technological Change:**

    - Net-zero goals and the transition to a more dynamic and dispersed energy network through decarbonization (including electrification), digitization, decentralization and democratization;
    - Responding to increased demand in the City of Burlington due to electrification and population growth;
    - Regulatory and policy changes mandated by the OEB, the MoE&E and others are frequent and can put a strain on resources;
    - Many companies are challenged to keep up with the latest technology platforms and their related application solutions;

- **Cyber Security:** Cyber Security risk management continues to be a top corporate priority with a focus on technology and business operations. With the evolving threat landscape and increasing risk to security of grid as part of critical infrastructure, Risk Management, Cyber Security, Privacy and Information Governance have become paramount components for business sustainability.

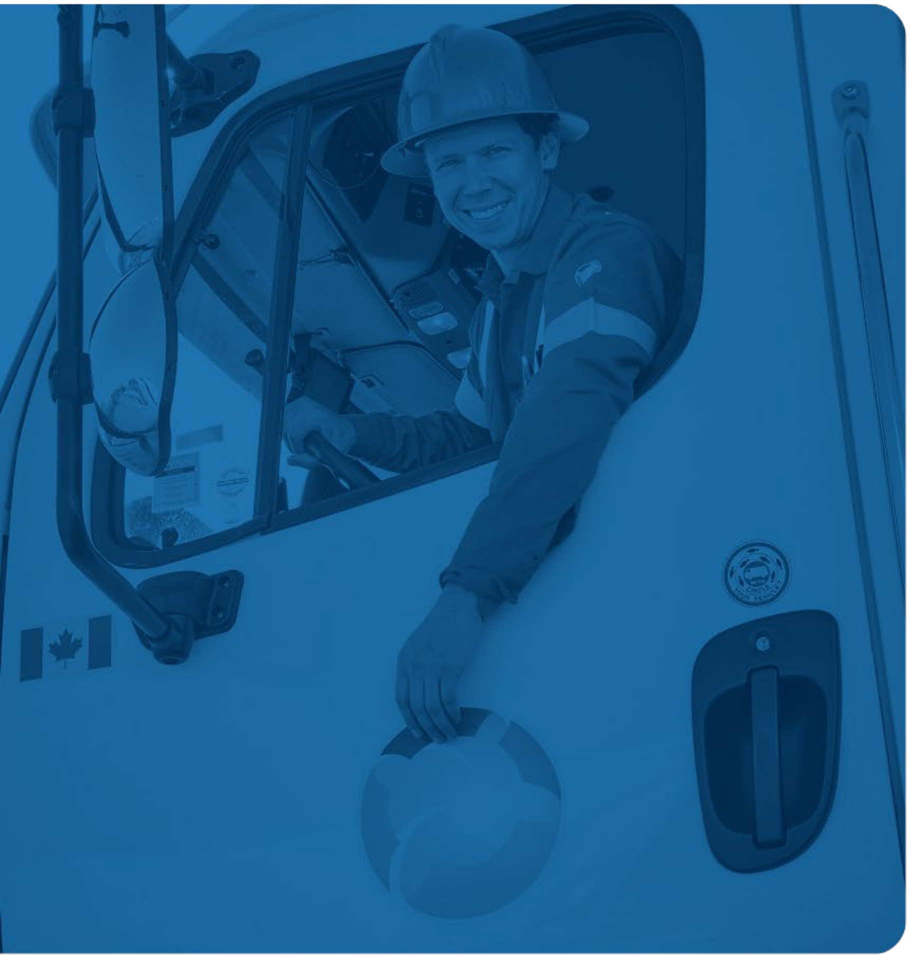
- **Health and Safety:** Our employees are exposed to high-voltage equipment, challenging physical environments, and extreme weather conditions, all of which creates risk of accidents and injuries. Due to the inherently hazardous nature of electrical work and infrastructure management that BHI operates within, the above elements could pose additional risk. In addition to protecting our workforce, we must also ensure the safety of the public by preventing incidents such as downed powerlines and electrical contact associated with our infrastructure.

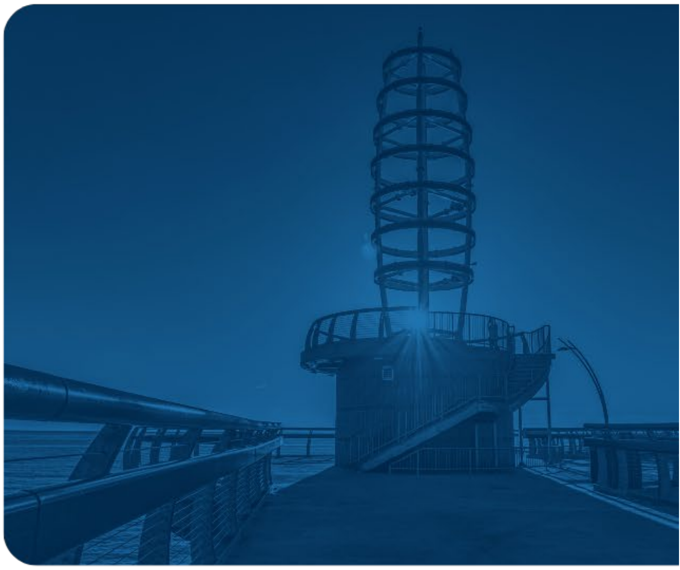
BHI addresses the mitigation and impact of these risks in its ongoing enterprise risk management framework. Mitigation strategies associated with the most significant risks include:

- **Service Disruption:** Power interruptions and reliability statistics are tracked and monitored by the System Control Supervisor; Min/Max inventory levels, vendor performance and impacts of major weather events across North America to Supply Chain are monitored by the Supply Chain Manager. Access to additional labor resources is available through the "Ontario Mutual Assistance Group" and agreements with contractors.
- **Employee Retention:** Employee satisfaction survey actions items are in place. Regular compensation surveys are conducted to ensure competitiveness. Focus on creating a sense of belonging and adopting best inclusivity practices are maintained to assist with employee retention/attraction.
- **Regulatory, Environmental and Technological Change:**
    - Maintain partnerships and a strong presence on all EDA Councils. This includes daily monitoring and participation across all facets of business.
    - Actively monitor, assess and implement revisions to policy, regulations and standards. Via GridSmartCity, use pilot projects to introduce potentially disruptive technologies to the grid. Pursue new business opportunities that result.
- **Cyber Security:**
    - Cultivating an environment of proactive risk management for information security, empowering our organization to operate securely in evolving threat landscape.
    - Aiming to protect Confidentiality, Integrity and Availability of organization Assets and Information by employing a defense in depth strategy.
    - Continuous compliance with OCSF in areas of Business Governance, Risk Management, Compliance, Privacy and Security Engineering.
    - Participating in Industry initiatives to protect organization systems and liaison with IESO, CCCS, Cyber Insurance Providers and Third-Party Auditors.
    - Ensuring compliance with standards related to Privacy controls through security frameworks.

- Implementing information systems controls to protect end to end enterprise processes, including supply chain, third party risk assessment, contractors and vendors by adopting Security Engineering methodologies.

- **Health and Safety:**
    - Continually enhance and implement BHI's comprehensive training program which includes safety protocols, emergency response, working at heights, and with high-voltage equipment.
    - Ensuring all employees have access to appropriate personal protection equipment. Conduct regular audits and inspections of work sites, vehicles and equipment to identify hazards and ensure a culture of continuous improvement.
    - Educate the public about electrical hazards, through public safety awareness programs.





Evaluation and Metrics – Balanced Scorecard

FINANCIAL

1. Earnings Before Interest and Taxes (EBIT) - $5.8M
2. Meet Shareholder Dividend of $2,697k
3. Meet financial metrics re: LDC Scorecard
4. Meet lender loan covenants
5. Successful 2026 Cost of Service Rate Application
6. Generate $100k to $150k of current or avoided cost savings through partnership in the GridSmartCity Cooperative.

INTERNAL PROCESSES AND OPERATIONAL EXCELLENCE

1. Meet Operational Effectiveness and Public Policy Responsiveness performance metrics Re: LDC Scorecard.
2. Expand implementation of digital file management systems to enhance accessibility, improve workflow efficiency, and reduce reliance on physical storage
3. Enhance digitalization roadmap and develop use case scenarios for AI automation
4. Create distribution system plan to accommodate growth, climate change and electrification (OMS)
5. Achieve OCSF cyber security requirements and successful audit

CUSTOMER AND COMMUNITY

1. Customer Satisfaction rating of 91% or higher.
2. Expand implementation of My Account portal furthering self-service and digitalization.
3. Implement a new Management System (OMS) with automated text integration to enhance customer experience.
4. Enhance customer service and stakeholder engagement framework.
5. Public Safety Survey – Exceed BHI rolling average and above provincial average.

LEARNING AND GROWTH

1. Lost Time Injury Frequency – zero lost time
2. Non-Lost time Injury Frequency – Meet 3 year rolling average
3. Create workforce plan to address changing landscape
4. Achieve all levels of WSIB excellence framework
5. Achieve Top employer status

Refer to Appendix D for the OEB's LDC Scorecard annual performance metrics

Appendices

A. Glossary of Terms

AFI	Advanced Metering Infrastructure
BEC	Burlington Enterprises Corp.
BESI	Burlington Electricity Services
BHEI	Burlington Hydro Electric Inc.
BHI	Burlington Hydro Inc.
CDM	Conservation and Demand Management
COS	Cost of Service
CIS	Customer Information System
CPI	Consumer Price Index
DER	Distributed Energy Resources
DSO	Distribution System Operator
DSP	Distribution System Plan
EBIT	Earnings Before Interest and Taxes
EDA	Electricity Distributors Association
EHRC	Electricity Human Resources Canda
ERM	Enterprise Risk Management
ESA	Electrical Safety Authority
EVs	Electric Vehicles
GIS	Geographic Information System
GSCC	GridSmartCity Cooperative
HEC	Hydro-Electric Commission
HR	Human Resources
HSEMS	Health, Safety, and Environment Management Systems
HVAC	Heating, Ventilation and Air Conditioning
H&S	Health and Safety
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standard
IRM	Incentive Regulation Mechanism
IT	Information Technology
kW	Kilowatt (measure of demand)
kWh	Kilowatt Hour (measure of consumption)
LDC	Local Distribution Company
MoE&E	Ministry of Energy and Electrification
MRP	Market Renewal Program
NRCan	Natural Resources Canada
OEB	Ontario Energy Board
OESP	Ontario Electricity Support Program
OCSF	Ontario Cyber Security Framework
OMS	Outage Management System
OM&A	Operations, Maintenance and Administration
OPA	Ontario Power Authority
ROE	Return on Equity
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQI	Service Quality Indicator
TS	Transformer Station
WSIB	Workplace Safety and Insurance Board

B. Comprehensive SWOT Analysis

Strengths:

Reliable and Robust Distribution System: Has a strong track record of providing a reliable electricity supply to its customers. The company has a well-developed infrastructure incorporating some modern equipment and technology. It can accommodate the City's aggressive growth plans and has adequate supply until 2035.

Strong Brand and Local Presence: The brand is highly recognized in industry and the community. It is viewed as a community supporter and is respected and trusted by all stakeholders and has the leverage to secure key partnerships.

Customer Centric Approach: Has consistently maintained an excellent customer service record and prioritizes the customer in its approach to operations.

Customer Base: Serves a diverse and stable customer base. Exposure to economic downturn is limited as a result.

Financial Stability: Has a stable financial position, allowing for future investments and expansion.

Organizational Structure and Compliancy: The company has a long history of operating in the City of Burlington and as a result has a well-developed structure and consistently overachieves regulatory and compliance obligations which provides for stability and predictability.

Employer of Choice and Skilled Workforce: The company is situated in an area that can and has attracted a highly skilled workforce from the top down. It has an employee-centric approach and is well known for its safety-first culture and excellent safety record. It is recognized as a Top Employer.

Weaknesses:

Aging Infrastructure: Its infrastructure is aging at a faster rate than replacement, requiring significant investment in upgrades and leading to potential maintenance issues and unexpected costs.

Limited Scale and Geographic Presence: The size of the company is considered medium, and it does not have the same economies of scale as a larger utility which can limit growth, investment, and productivity savings. Its operations are limited to a specific geographic area, limiting growth opportunities.

Workforce Renewal, Engagement and Upskilling Required: The workforce has changed over at a significant rate which has caused a loss of knowledge of processes. The energy transition will require a significant change to workforce structure and skills required to adapt.

Limited Innovation: The company has some legacy IT/OT/IOT infrastructure along with a historical siloed approach to investing and maintaining its technologies. This can lead to missed opportunities to reduce costs and adapt to changing customer and employee preferences.

Opportunities:

The Energy Transition, Electrification and Renewable Energy: There is an opportunity to invest in renewable energy sources and contribute to the transformation of the Industry and Community such as solar, EV charging, storage, and electric heating. While at the same time, be viewed as an enabler for customers and partners to meet their sustainability goals and regulatory requirements.

Infrastructure and Grid Modernization: Integrating new technologies and distributed energy resources into the distribution system can enhance efficiency, reliability, resiliency, and growth opportunities.

Electric Vehicle Infrastructure: With the growth of electric vehicles, there is an opportunity to invest in charging infrastructure and services pending changes in regulations.

Systems, Data Analytics and AI: Modernizing systems, and investing in data analytics and AI will enable BHI to improve operations such as customer service and offerings, facilitate energy usage analysis, optimize asset management, and effectively manage or prevent outages.

Threats:

Regulatory Changes and Uncertainty: The company operates in a highly regulated environment as such changes in government and regulatory policies and regulations could impact operational improvements and rate of return.

Cybersecurity Risks: The company is vulnerable to cybersecurity threats, which can disrupt operations and erode customer trust. Growing digitization and system adoption, shadow IT/OT/IOT infrastructure and/or lack of investment in IT resources can increase the risk of damage to operations.

Climate Change and Natural Disasters: Climate change is having an impact on the frequency of events such as extreme weather and storms. As such, can damage infrastructure and disrupt service delivery.

Competitive Labour Market: The aging workforce has caused a shortage of skills which could impact on our ability to attract and retain employees. The post pandemic has had a major shift in employee preferences to work environment and compensation packages.

C. 2025 Action Plans

1. Financial Stewardship

1.1 Responsible Financial Management

1. Monitor and measure BHI performance against goals and industry benchmarks.
2. Monitor and leverage IESO/OEB policies, funding models and funding availability. Secure additional funding through lenders as required.
3. Ensure Board Members and Senior Staff are well apprised of financial risks/opportunities tied to organizational threats and weaknesses.

1.2 Efficiencies

1. Grow the shared services model with GridSmartCity LDC members to collectively procure or deliver services and materials more cost efficiently. This will include services/resources with respect to: benefits; inventory (poles, wire/cable, transformers); fleet outsourcing; service outsourcing; etc.

1.3 Capital Planning

1. Develop plans to fund growth driven by housing, development and electrification.
2. Maintain optimal Asset Management plans.

1.4 Regulatory Compliance

1. Leverage lessons learned from recent Cost of Service application and refine processes to optimize for 2026-2030 Cost of Service application.
2. File and defend the 2026 Cost of Service rate application.

2. Internal Processes and Operational Excellence

2.1 Reliability & Resilience

1. Implement proactive maintenance strategies to protect against extreme weather events.
2. Maintain current release levels on Application Systems to ensure maximum functionality, reliable support and return on investment of Annual Maintenance.
3. Support implementation of the City of Burlington's Climate Action Plan and the Climate Change Adaptation Plan.

2.2 Efficiencies & Digitalization

1. Implement standardized and automated business processes for productivity improvements and better outcomes.
2. Centralize supplies and optimize facility space.
3. Investigate improved warehouse management workflows and space optimization along with enhanced yard security and outside storage materials management workflows.
4. Use Contractor Compliance to manage Contractors and deliver their H&S Orientation.
5. Successfully integrate and implement an OMS for the Operations and Engineering departments to manage projects and outages effectively.
6. Integrate and optimize digital file management systems to enhance document accessibility, improve workflow efficiency, and reduce reliance on physical storage.

2.3 Electrification & Growth

1. Prepare local grid for higher demand.
2. Replace and upgrade infrastructure to meet growing demand and support electrification.

2.4 Governance & Risk Management

1. Continuous Improvement and adaptation of BHI's Cyber Security Management Program in response to changing Threat Landscape.

3. Customer and Community

3.1 Customer Service

1. Implement a customer service Strategic Plan to instill a customer service culture across the entire organization.
2. Ensure customers are well informed of operating measures – from our commitment to keep the lights on, to programs and payment options available to help those struggling to pay their electricity bill.

3.2 Customer Satisfaction and Engagement

1. Conduct annual customer satisfaction surveys and implement key recommendations within our control.
2. Establish a comprehensive plan to improve customer engagement with targeted programs and initiatives that align with customer needs and preferences.
3. Introduce an automated alert system to notify customers of planned and unplanned outages via SMS, email, and website updates, improving transparency and customer satisfaction during outages.

3.3 Public Safety

1. Implement an ongoing public safety campaign in response to ESA Safety Survey.
2. Partner with ESA and other LDCs on a refreshed Public Safety campaign and an enhanced Safe Schools program.

3.4 Communications & Branding

1. Ensure customer understanding of BHI Value Proposition to community.
2. Build on communications strategy to include:
    - Profiles of successes and cost-effective electricity distribution
    - GridSmartCity and BHI Brand Building
    - Promotion of BHI as a "Great Place to Work," "Employer of Choice," and "Safe Employer"
3. Engage Staff to conduct a brand refresh that includes organizational purpose and identity. Create an implementation and execution plan.

4. Learning and Growth (Employer of Choice)

4.1 Workforce Planning & Development

1. Enhance Staff Training and Development Plan to ensure upskilling and extension of IT capabilities to address changing landscape.
2. Implement functional staff cross-training and improve process documentation to improve capability redundancy among staff.
3. Conduct a workforce planning strategy to ensure effective attraction and retention.
4. Further enhance recruitment strategies to ensure inclusivity.
5. Ensure succession plans are in place for key positions.

4.2 Employee Engagement & Culture

1. Continue to reinvigorate relationships that will promote desired culture.

4.3 Adaptation to Innovation

1. Develop personnel capabilities to accommodate diverse technologies in support of net-zero goals.

4.4 Health & Safety

1. Take steps to participate in a recognized a new Safety Management System that promotes health and safety excellence and takes us beyond WSIB Safety Excellence program.
2. Meet safety metric of the OEB Scorecard.
3. Utilize the training matrix by position within SafeTapp to ensure employees are up-to-date on safety requirements.

D. LDC Scorecard

Burlington Hydro has a business culture that promotes continuous adjustment and improvement to ensure it delivers value in the services it provides to its customers.

The Ontario Energy Board's LDC Scorecard reports annual performance metrics for each electricity utility in Ontario, including Burlington Hydro. The scorecards are a way to track performance year over year and compare to other utilities' performance. The scorecard provides data for specific measures in the following four key areas of performance:

- Customer focus
- Operational effectiveness
- Public policy and responsiveness
- Financial performance

The OEB uses scorecards to help monitor an individual utility's performance and to compare performance across the sector. Comparisons are critical to its rate-setting process, and through them, it can determine if corrective action is need.

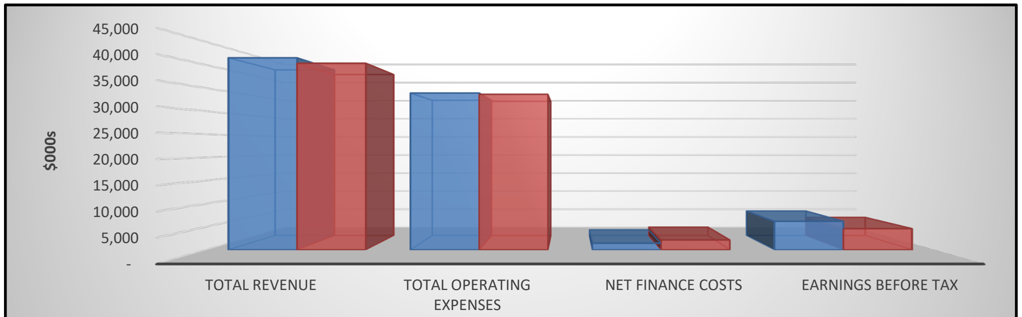
Review the 2023 Scorecard:
https://www.burlingtonhydro.com/images/pdfs/2023_Scorecard_MDA_BHI_Final.pdf

Part B
Pro Forma & Financial Statements

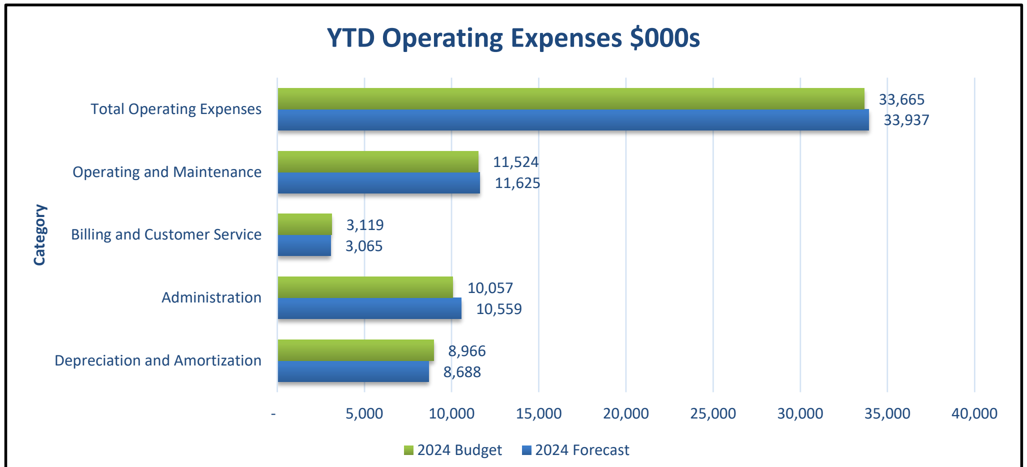
2024 Forecast

Pro Forma Financial Statements

OPERATING PERFORMANCE DASHBOARD - 2024 FORECAST



	Total Revenue	Total Operating Expenses	Net Finance Costs	Earnings Before Tax
2024 Forecast	41,562	33,937	1,442	6,183
2024 Budget	40,393	33,665	2,140	4,588

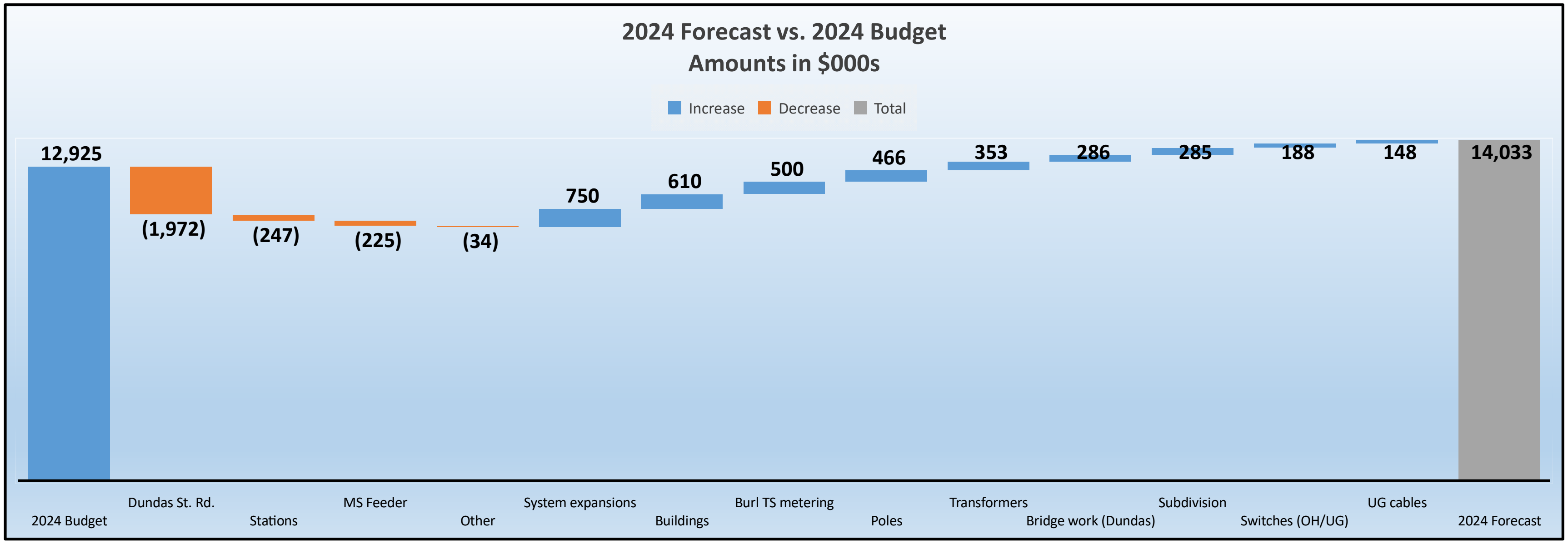


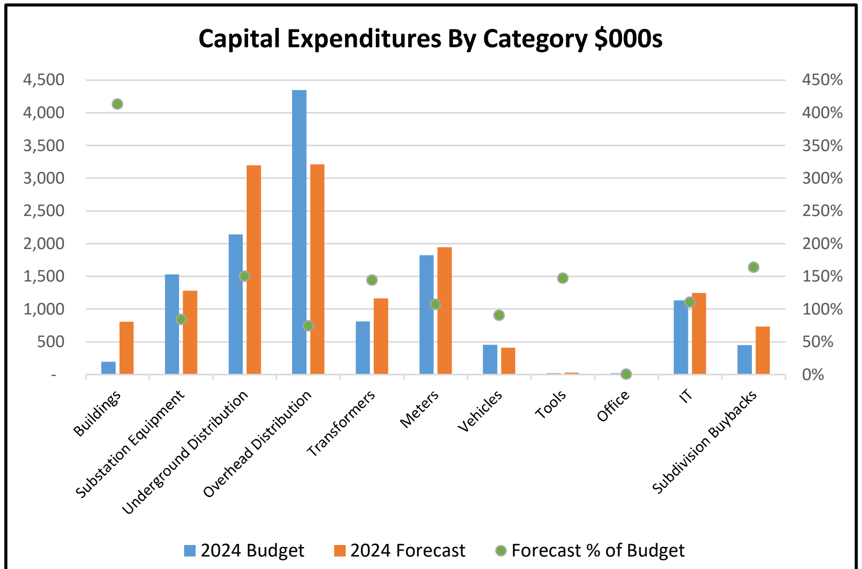
EARNINGS BEFORE INTEREST AND TAX

$7.62M	$6.73M	113%
2024 Forecast	**2024 Budget**	**% of Budget**

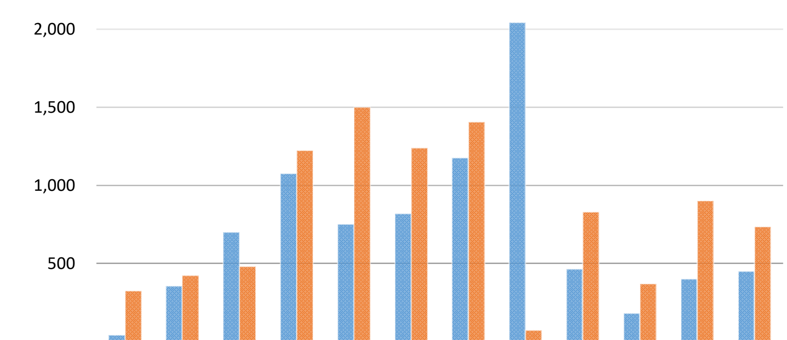
$000's	2024 Forecast	2024 Budget	F/(U)	% Budget
DISTRIBUTION REVENUE	37,106	36,820	287	101%
OTHER OPERATING REVENUE	2,858	1,764	1,094	162%
DEFERRED REVENUE	1,598	1,810	(212)	88%
TOTAL REVENUE	**41,562**	**40,393**	**1,169**	**103%**
O&M	11,625	11,524	(101)	101%
B&CS	3,065	3,119	54	98%
ADMIN INCL PROPERTY TAX	10,559	10,057	(502)	105%
TOTAL OPERATING EXP	**25,249**	**24,700**	**(549)**	**102%**
DEPRECIATION	8,688	8,966	277	97%
EBIT	**7,625**	**6,728**	**897**	**113%**
NET FINANCE COSTS	1,442	2,140	698	67%
NET INCOME BEFORE TAX	**6,183**	**4,588**	**1,595**	**135%**
TOTAL TAXES	711	528	(183)	135%
NET INCOME AFTER TAX	**5,472**	**4,060**	**1,412**	**135%**

CAPITAL EXPENDITURES DASHBOARD - 2024 FORECAST





Major Programs $000s



	1340 Brant St.	Stn TX	Stn SWG	U/G cables	GS U/G	Poles	GS O/H	Dundas Rd.	Dist. TX Rpl	SW OH/UG	Burl TS Mt	Sub Buybck
2024 Budget	40	355	700	1,076	750	818	1,175	2,044	465	180	400	450
2024 Forecast	323	422	480	1,224	1,500	1,240	1,406	72	829	368	900	735

2024 Budget 2024 Forecast

2024 Forecast

MANAGEMENT DISCUSSION & ANALYSIS (MD&A)

Earnings Before Tax (EBT)

- EBT of **$6,183k** is expected to be **$1,595k or 135%** favorable vs. the budget of $4,588k primarily due to:
  - favorable other operating revenue of **$882k** (including deferred revenue) primarily driven by:
    - management fees billed for the Metrolinx GO Corridor Electrification and Burloak Grade Separation projects of $752k which attract fees for BHI's management costs; and
    - interest on regulatory balances of $278k; offset by
    - lower depreciation on projects funded through contributed capital $(212)k
  - favorable net finance costs of **$698k** driven by higher cash balances and lower interest on long term debt (the budget anticipated drawing down the remaining $10M TD term loan. This was originally required to be drawn down to 2023 and can be extended as late as 2026);
  - favorable distribution revenue **$287k**
  - favorable depreciation expense **$277k** due to lower capital expenditures than budgeted partly offset by:
  - unfavorable operating expenses of **$(549)k**

Distribution Revenue

- Distribution Revenue of **$37,106k** is expected to be **$287k** favorable vs. the budget of $36,820k due to a higher number of residential customers and higher consumption/demand for commercial customers than budgeted.

Operating Expenses

- Operations & Maintenance (Control Room /Stations /Meter Shop/ Distribution (Lines)) costs are forecast to be unfavorable vs. budget by **$(101)k** due to:
  - Scadamate Switch Maintenance ($175k) which was unplanned and not conducted on a proactive basis in the past. High failure rates of these units in 2023 and 2024 warranted completing maintenance on all units and implementing a proactive maintenance program on a 5-year cycle
  - Locates ($75k) due to higher locate requests as compared to budget
  - Vegetation Management ($55k) due to increased storm activity; partly offset by
  - Wages which are favorable as compared to budget driven by (i) vacancies and partly offset by (ii) a higher percentage of labour allocated to operating activities for station maintenance

- Billing & Collecting (Billing Department, Call Centre, Meter Reading) costs are forecast to be **$54k** favorable vs. budget due to:
  - postage and stationery favorability and vacancies.

- Administration Department (Executive, Human Resources, IT, Purchasing, Regulatory, Safety, Communications, Accounting, Board of Directors) costs are forecast to be unfavorable vs. budget by **$(502)k** due to:
  - ($183k) salaries and benefits higher than budgeted due to the hiring of support staff - an executive assistant and temporary staff in HR;
  - ($82k) hosting services and software support for BHI's CIS and imaging/workflow software for accounts payable
  - ($76k) due to higher costs allocated to LDCs by the OEB; and increased costs associated with filing the 2026 Cost of Service rate application
  - ($58k) legal fees associated with collective bargaining and settlements

Capital Expenditures

BHI - 2024 FORECAST CAPITAL EXPENDITURES	2024 FORECAST	2024 BUDGET	VARIANCE $ Incr/(Decr)	VARIANCE % Fcst
GROSS CAPITAL	29,714	29,299	415	101 %
CONTRIBUTED CAPITAL	(15,682)	(16,374)	692	96 %
NET CAPITAL	**14,033**	**12,925**	**1,107**	**109 %**
BUILDINGS	805	195	610	413 %
SUBSTATION EQUIPMENT	1,283	1,530	(247)	84 %
U/G PROJECTS	3,199	2,141	1,059	149 %
O/H PROJECTS	3,212	4,345	(1,133)	74 %
TRANSFORMERS	1,164	811	353	144 %
METERS	1,946	1,826	120	107 %
ROLLING STOCK	410	455	(45)	90 %
TOOLS	29	20	9	147 %
COMPUTER HARDWARE/SOFTWARE	1,248	1,132	116	110 %
OFFICE EQUIPMENT	—	20	(20)	— %
SUB TOTAL	**13,298**	**12,475**	**822**	**107 %**
DEVELOPER BUYBACKS	735	450	285	163 %
TOTAL CAPITAL EXPENDITURES	**14,033**	**12,925**	**1,107**	**109 %**

- **Net Capital Expenditures** are forecast to be **$1,107k** higher than the 2024 budget driven by:
  - Buildings $610k - Replacement of a section of the roof at 1340 Brant Street that is beyond economic repair, replacement/refurbishment of the receiving dock, and construction of a retaining wall in the yard;
  - U/G Projects $1,059k – Higher expenditures on i) system expansion projects, ii) U/G cables to address faults, and iii) duct hanger inserts at the Dundas Street bridge crossing, partially offset by cancellation of the MS Feeder cable replacement project;
  - Transformers $353k - Increased expenditures to replace leaking/faulty transformers;
  - Meters $120k - Higher expenditures on the Burlington TS metering replacement, partially offset by lower spending on electricity suite metering;
  - Computer Hardware/Software - Higher expenditures to replace end-of-life network switches and for ERP enhancements/upgrades;
  - Developer buybacks $285k - Increased expenditures to buy back subdivision assets from developers;

  partly offset by the following deceases:

  - Substation Equipment $(247)k –The installation of additional 2 Switchgear units was cancelled; and
  - O/H projects $(1,133)k – the Dundas Road widening project was delayed until 2025.

- **Contributed Capital** is forecast to be $692k lower than the 2024 budget driven by:
  - $2,966k Delayed Dundas Rd Widening project until 2025;
  - $516k Revised estimate for the Burloak Grade Separation project;

  partly offset by the following increases:

- $(2,070)k - higher cost recovery for Phases 1.1 and 9.1 of the Metrolinx corridor electrification project due to an increase in project completion estimates; and
- $(728)k - higher demand for General Service U/G projects.

2024 Dividends

BHI - 2024 DIVIDENDS DECLARED TO BEC $000s	DATE	2024 FORECAST	2024 BUDGET	COMMENTS
Q4 PRIOR YEAR	Mar-2024	184	723	Completed
WORKING CAPITAL BEC	Mar-2024	50	50	Completed
Q1 CURRENT YEAR	Mar-2024	417	417	Completed
Q2 CURRENT YEAR	Jun-2024	417	417	Completed
Q3 CURRENT YEAR	Sep-2024	417	417	Completed
Q4 CURRENT YEAR	Dec-2024	417	417	Proposed
SPECIAL DIVIDEND - CAP STUDY	Sep-2024	58	173	Completed
SPECIAL DIVIDEND - FORESTRY LEASE	Dec-2024	116	115	Proposed
TOTAL		**2,076**	**2,727**	

- Regular Dividends are forecast at $2,076k for 2024, which includes a $184k true-up payment for 2023 actuals and reflects the new dividend policy.
- Special Dividends are forecast at $173k as compared to the budget of $287k which represents:
  - $58k for BEC for the completion of the Sustainability Plan on behalf of the City of Burlington to support their Climate Action Plan - the project cost was lower than anticipated; and
  - $116K for the property and trailer lease for the City of Burlington Forestry Group.

2025 Budget and 2026 Forecast

Pro Forma Financial Statements

2025 Budget and 2026 Forecast

ASSUMPTIONS

Regulatory Inputs

- BHI's rates are set under the Price Cap IR (Incentive rate-setting) methodology which is a Cost of Service year typically followed by 4 years adjusted using an inflationary formula
  - BHI filed a Cost of Service application for rates effective May 1, 2021 after six years of inflationary increases
  - 2025 is BHI's fourth Incentive Rate-Setting Mechanism (IRM) application following the 2021 Cost of Service. Under the IRM process, base rates for electricity distributors are adjusted by a mechanism that is based on an OEB inflation factor less a productivity or X-Factor. The formula includes an industry-specific inflation factor and two factors for productivity - one productivity factor is a fixed amount for industry wide productivity and the other is a stretch factor
  - The ***OEB inflation factor*** is intended to reflect the LDC's growth in input prices and is calculated using 70% of the annual growth in GDP-IPI and 30% of the annual growth in Average Weekly Earnings. A 1% change in OEB inflation represents approximately $380k in distribution revenue.
  - The ***productivity factor*** for IRM applications is currently set at 0% by the OEB.
  - BHI's ***stretch factor*** is 0.15% - BHI is in the 2nd cohort group (actual costs are 10-25% lower than predicted costs). A 0.15% change in the stretch factor represents approximately $55k in distribution revenue.
- The OEB inflation factor for 2025 is 3.60%. BHI's distribution rates will increase by 3.45% effective January 1, 2025 (OEB inflation less BHI's stretch factor of .15%)

Group I **SF = 0%** **17 LDCs**	***Group II*** **SF = .15%** **15 LDCs**	***Group III*** **SF = .30%** **17 LDCs**	***Group IV*** **SF = .45%** **3 LDCs**	***Group V*** **SF = .60%** **2 LDCs**
Cooperative Hydro Embrun	**Burlington Hydro**	Alectra Utilities	Canadian Niagara Power	Algoma
E.L.K. Energy	Centre Wellington	Atikokan Hydro	Hydro One	Toronto Hydro
Entegrus Powerlines	EPCOR Electricity Disctribution	Bluewater Power Distribution	Hydro Ottawa	
ENWIN Utilities	Fort Frances Power	Chapleau Public		
Essex Powerlines	GrandBridge Energy Inc.	Elexicon Energy		
Grimsby Power	Hydro 2000 Inc.	Enova Power		
Halton Hills Hydro	Kingston Hydro	ERTH Power		
Hearst Power Distribution	Lakeland Power Distribution	Festival Hydro		
Hydro Hawkesbury	Newmarket-Tay Power	Greater Sudbury Hydro		
Lakefront Utilities	Niagara-on-the-Lake	Innpower		
Milton Hydro	**Niagara Peninsula Energy**	London Hydro		
Northern Ontario Wires	Oshawa PUC	North Bay Hydro Distribution		
Orangeville Hydro	Rideau St. Lawrence Distribution	Oakville Hydro		
Ottawa River Power	Tillsonburg Hydro	PUC Distribution		
Sioux Lookout Hydro	**Westario Power Inc.**	Renfrew Hydro		
Wasaga		Synergy North		
Welland Hydro		Wellington North Power		
				Change vs. PY
				GSC Members

Stretch Factor Assignments by Group

- Stretch factor assignments are based on the results of an OEB statistical cost benchmarking study designed to make inferences on individual distributors' cost efficiency. Distributors that had actual costs that were lower than that predicted by the model are considered to be better cost performers and are assigned lower stretch factors than those that did not.

- Stretch Factors are determined on an annual basis and deducted from inflation to determine an LDC's rate increase in a non-Cost of Service year.

2026 Cost of Service Application

- BHI is scheduled to file its next Cost of Service application in March 2025 for 2026 rates.
  - A Cost of Service application sets a price for a service based on the costs to provide it
  - OEB approves revenue for the year (2026) which is based on the sum of:
    - Rate of Return on Capital Expenditures and Working Capital
    - Operating expenses
    - Depreciation
    - Interest Expense
    - Income Tax
  - Distribution revenue is allocated to rate class based on cost to serve that rate class.
  - Rates to recover that revenue are determined based on estimated customer count and consumption/demand.
  - Revenue for four + subsequent years is based on the Cost of Service year + inflationary increases.

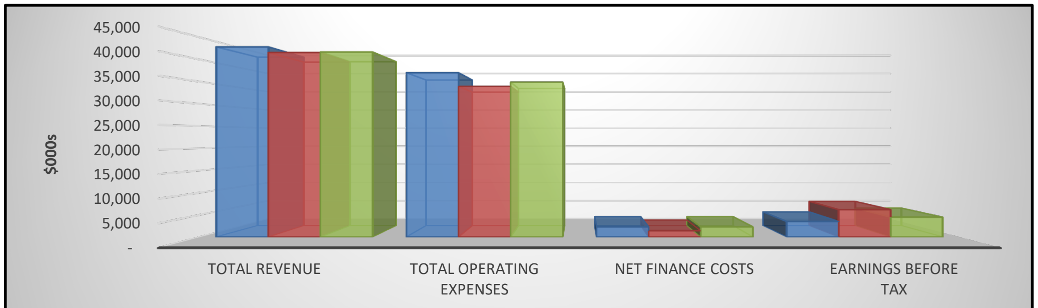
Price Cap IR	Year 1 [1]	Year 2	Year 3	Year 4	Year 5	Year 1 [1]
	May 1 2021	May 1 2022	May 1 2023	May 1 2024	Jan 1 2025	Jan 1 2026
	Cost of Service	IRM	IRM	IRM	IRM	Cost of Service
OEB Inflation		3.30%	3.80%	4.80%	3.60%	
Stretch Factor		0.15%	0.15%	0.15%	0.15%	
% Rate Increase		3.15%	3.65%	4.65%	3.45%	

1. Rates set on Cost of Service Basis

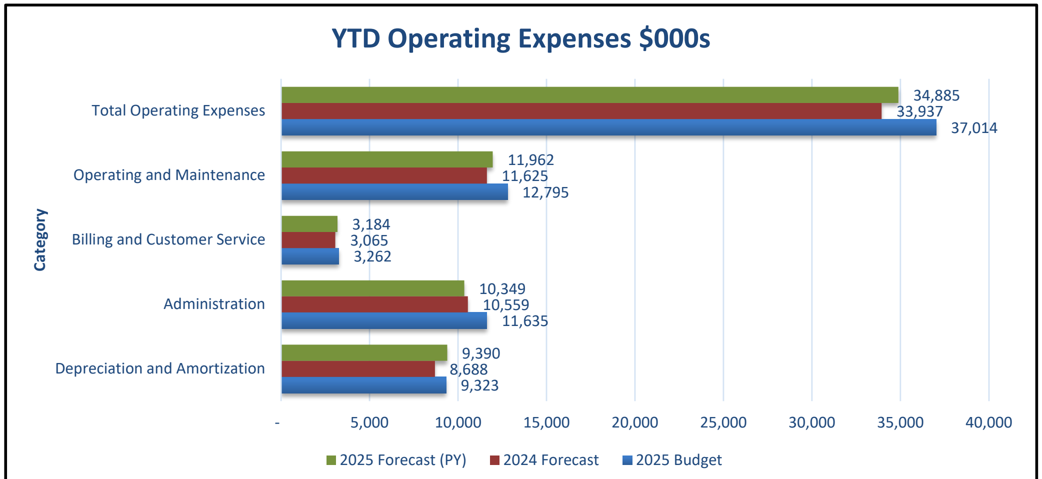
- The OEB sets the Cost of Capital Parameters, which determine a distributor's deemed equity and debt, on an annual basis. The Cost of Capital Parameters are effective for the entire Price Cap IR term and are updated for a distributor at each Cost of Service. The Cost of Capital Parameters for BHI's 2026 Application will not be available until October of 2025.

Rate	2021 CoS	2024	2026 CoS
Return on Equity (ROE)	8.34%	9.21%	TBD
Deemed Long-Term Debt Rate	2.85%	4.58%	TBD
Deemed Short-Term Debt Rate	1.75%	6.23%	TBD
Weighted Average Cost of Capital (WACC)	**5.00%**	**6.50%**	**TBD**

OPERATING PERFORMANCE - 2025 BUDGET



	Total Revenue	Total Operating Expenses	Net Finance Costs	Earnings Before Tax
2025 Budget	42,827	37,014	2,302	3,510
2024 Forecast	41,562	33,937	1,442	6,183
2025 Forecast (PY)	41,672	34,885	2,305	4,482



EARNINGS BEFORE INTEREST AND TAX

$5.81M	$7.62M	$6.79M
2025 Budget	2024 Forecast	2025 Forecast (PY)

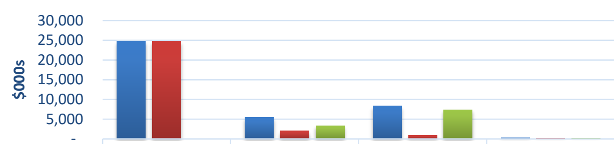
$000's	2025 Budget	2024 Forecast	F/(U)	% Fcst
DISTRIBUTION REVENUE	38,878	37,106	1,772	105%
OTHER OPERATING REVENUE	1,989	2,858	(869)	70%
DEFERRED REVENUE	1,959	1,598	361	123%
TOTAL REVENUE	**42,827**	**41,562**	**1,265**	**103%**
O&M	12,795	11,625	(1,170)	110%
B&CS	3,262	3,065	(197)	106%
ADMIN INCL PROPERTY TAX	11,635	10,559	(1,076)	110%
TOTAL OPERATING EXP	**27,692**	**25,249**	**(2,443)**	**110%**
DEPRECIATION	9,323	8,688	(635)	107%
EBIT	**5,812**	**7,625**	**(1,813)**	**76%**
NET FINANCE COSTS	2,302	1,442	(860)	160%
NET INCOME BEFORE TAX	**3,510**	**6,183**	**(2,673)**	**57%**
TOTAL TAXES	404	711	307	57%
NET INCOME AFTER TAX	**3,106**	**5,472**	**(2,366)**	**57%**

REVENUE - 2025 BUDGET

DISTRIBUTION REVENUE

$38.9M	$37.1M	105%
2025 Budget	2024 Forecast	% of Forecast

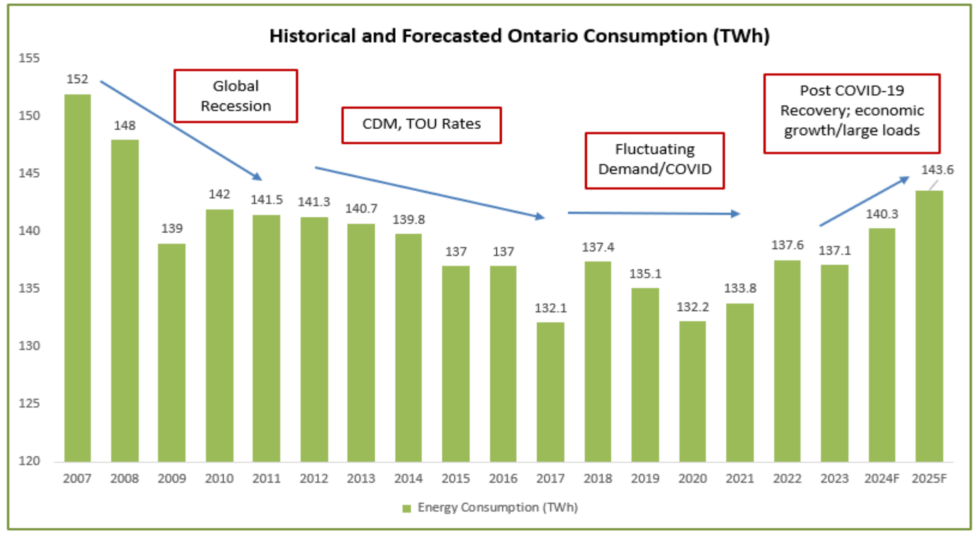
2025 Distribution Revenue by Rate Class



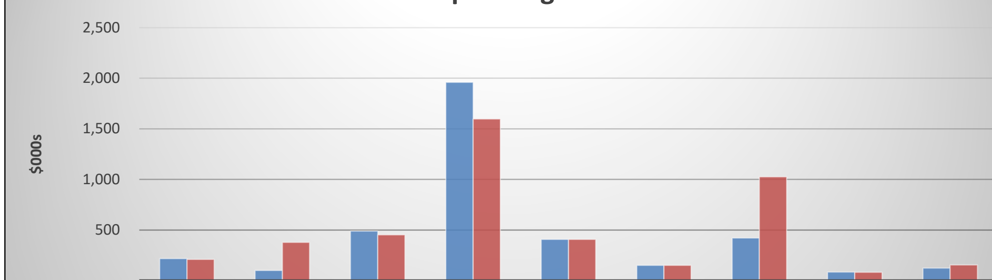
	Residential	Small Commercial	Large Commercial	Other
Total	24,787	5,418	8,334	339
Fixed	24,787	2,046	910	210
Variable	-	3,372	7,423	129

OTHER REVENUE

$3.95M	$4.46M	89%
2025 Budget	2024 Forecast	% of Forecast



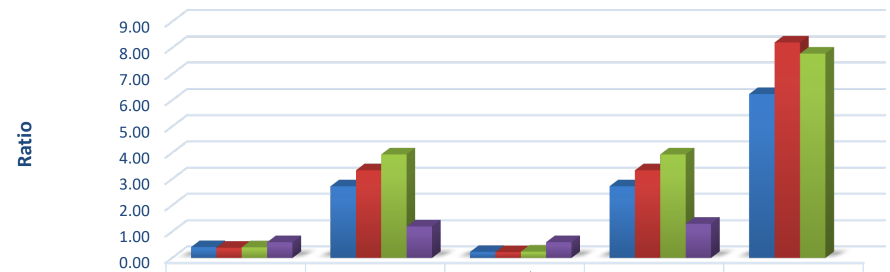
Other Operating Revenue



	LATE PAYMENT CHARGES	CARRYING CHARGES ON REG ACCOUNTS	BILLING SERVICES - BESI	DEFERRED REVENUE	POLE RENTAL	OCCUPANCY CHANGE	PROJECTS	PROPERTY LEASE	ALL OTHER
2025 Budget	217	100	489	1,959	407	150	420	84	123
2024 Forecast	210	378	452	1,598	407	150	1,025	81	155

BALANCE SHEET - 2025 BUDGET

MIFRS BALANCE SHEET	2025 Budget	2024 Forecast	2023 Actuals
Working Capital ($000s)	6,026	6,230	8,214
Inventory ($000s)	5,874	5,606	5,486
Current Ratio	1.12	1.12	1.15
Total Assets ($000s)	313,674	293,297	284,224
Total Liabilities ($000s)	215,234	195,216	189,537
Total Equity ($000s)	98,441	98,081	94,687



	TD - Debt/Capital	TD - Debt Service	IO - Debt/Total Assets	IO - Debt Service	Interest Coverage
2025 Budget	0.41	2.7	0.23	2.7	6.2
2024 Forecast	0.39	3.3	0.22	3.3	8.2
2023 Actuals	0.40	3.9	0.24	3.9	7.8
Lender Covenant	0.60	1.2	0.60	1.3	

CREDIT AND BORROWING OPTIONS

$20M	$18M	$10M
Operating Loan	Letter of Credit	Available Debt

BHI - 2025 BUDGET LONG TERM DEBT	Amount	Term	Date	Maturity	Rate	O/S 2025	Purpose
Infrastructure Ontario #1	$10M	15 yrs	Mar-2011	Mar-2026	4.51%	$0.2M	Smart Meters and capital program
Infrastructure Ontario #2	$8M	25 yrs	Mar-2013	Mar-2038	4.02%	$4.9M	Hydro 1 TS capital contributions/capital program
Infrastructure Ontario #3	$7M	15 yrs	Dec-2018	Mar-2033	3.63%	$4.2M	Tremaine TS/Breakers and capital program
TD Term Loan - Drawdown #1	$5M	10 yrs	Mar-2021	Mar-2031	2.47%	$2.8M	Overall capital program
TD Term Loan - Drawdown #2	*$5M*	*10 yrs*	*Jan-2025*	*Jan-2035*	*5.35%*	*$9.2M*	*Overall capital program*

S/H Note	$47,878,608	2.85%

Additional Borrowings ($M)	
2025-2026 (to next CoS)	$20
2025-2034 (10-year plan)	$115

2025 Budget

MANAGEMENT DISCUSSION & ANALYSIS (MD&A)

Earnings Before Tax (EBT)

- EBT of **$3,510k** is expected to be **$(2,673)k** unfavorable vs. the 2024 Forecast of $6,183k primarily due to:
  - unfavorable other revenue of **$(869)k** driven by:
    - Management fees billed for the Metrolinx GO Corridor Electrification and Burloak Grade Separation projects of ($605k). These projects attract fees for BHI's management costs and the bulk of the work is expected to be completed in 2024; and
    - interest on regulatory balances of ($278k) – regulatory balances represent amounts owing to/due from customers. Balances due from customers are lower in 2025 as a portion of these balances will be recovered from customers throughout 2024 and 2025;
  - unfavorable depreciation expense **$(635)k** due to a full year of depreciation on 2024 additions, and ½ year depreciation on 2025 additions, partly offset by assets which are expected to be fully depreciated at the end of 2024;
  - unfavorable net finance costs of **$(860)k** driven by higher interest on long term debt (the 2025 budget anticipates drawing down the remaining $10M of the TD term loan); and
  - unfavorable operating expenses of **$(2,443)k**

    partly offset by

  - favorable distribution revenue of **$1,772k**
  - favorable deferred revenue of **$361k** driven by a full year of depreciation on 2024 additions
    - Deferred Revenue reflects IFRS accounting treatment for the receipt of capital contributions for projects. Capital Contributions are received from customers for different capital projects consistent with BHI's Conditions of Service. Contributions received are recorded on the Balance Sheet as both a PP&E asset and as a Deferred Revenue liability.
    - The Deferred Revenue Liability is amortized and recorded on the P&L as Miscellaneous Revenue over the life of the asset. The PP&E asset also is depreciated at the same rate with an equal and offsetting Depreciation Expense recorded on the P&L, resulting in no "bottom line" impact to the P&L.

- EBT in 2025 is expected to be lower than prior years as (i) BHI fills vacant positions (ii) the Metrolinx GO Corridor Electrification projects, which earn management fees, start to wind down and (iii) BHI experiences increased costs associated with 3rd party services such as tree trimming.

Distribution Revenue

- Distribution Revenues will be set under the IRM process for 2025. Revenues of $38,878k are expected to be $1,772k favorable vs. the 2024 forecast of $37,106k primarily driven by the inflationary increase in rates of 3.60% .

  Consumption/Demand/Customer Forecasts

  - The forecast for 2025 energy (kWh), demand (kW) and # of customers is based on historical patterns. BHI conducted a comprehensive regression analysis to forecast customer counts, consumption and demand, as part of the requirements for its Cost of Service Application

  - Any changes in consumption and demand impact revenue for small and large commercial customers as the residential rate class is billed on a fixed basis. Customer growth has been relatively flat in 2024. Assumptions for 2025 include:
    - Customer growth of 0.5% and 1.0% for residential and GS<50 customers respectively;

- kWh increase of approximately 1% for rate classes billed on consumption (small commercial, USL) due to economic growth, and additional EV and heating loads;
- kW (demand) decrease of approximately 3% for large commercial customers. Although this class will experience growth due to the economy, EVs and electric heating, this consequent increase in demand is more than offset by conservation savings from energy efficiency programs which are currently geared toward large commercial customers
- In general, a significant increase in load related to electrification of transit and heating is not expected to impact consumption and demand until post 2026.

Operating Expenses

- 10% overall increase vs. the 2024 Forecast

- Payroll Budget Assumptions
  - 4.25% annual increase for non-union staff
  - 3.75% annual increase for union staff based on new collective agreement
  - 6.0% increase vs. the 2024 forecast driven by Group Life 5%, LTD Benefits 3%, Extended Health Benefits 0%, Dental Benefits 18%

- Operations & Maintenance (Control Room /Stations /Meter Shop/ Distribution (Lines)) costs are forecast to be unfavorable vs. the 2024 forecast by **$(1,170)k** due to:
  - $(784)k operations and engineering labour driven by inflationary increases in wages, filling vacancies, and a higher percentage of time allocated to operating expenses versus capital; partly offset by the transfer of two staff to Information Technology; and
  - $(480)k tree trimming costs driven by higher third party labour costs; partly offset by
  - $87k asset removals/inspections/maintenance - 2024 included preventative maintenance for the majority of BHI's Scadamate Switches. In 2025 this maintenance will be performed on a 5-year cycle.

- Billing & Collecting (Billing Department, Call Centre, Meter Reading) costs are forecast to be **$(197)k** unfavorable vs. the 2024 forecast due to:
  - replacement of temporary staff with permanent hires $(102)k
  - an increase in third party settlement and meter reading costs of $(66k)

- Administration Department (Executive, Human Resources, IT, Purchasing, Regulatory, Safety, Communications, Accounting, Board of Directors) costs are forecast to be **$(1,076)k** unfavorable vs. the 2024 forecast due to:

  - $(530)k in salaries, benefits and temporary staff due to inflation, the transfer of two staff from Engineering to Information Technology, and a full year of compensation for the executive assistant;
  - $(148)k bonus payments due to an increase in the number of eligible employees;
  - $(248)k in information and technology costs for general software support and maintenance, increased ERP software support to facilitate automation, an increase in hosting services for BHI's CIS, and a subscription for 3rd party IT support services; and
  - $(120)k for other expenses including communications, insurance, conferences, and OEB costs;

  partly offset by

  - $79k in legal fees associated with collective bargaining and settlements

Capital Expenditures

BHI - 2025 BUDGET CAPITAL EXPENDITURES	2025 BUDGET	2024 FORECAST	VARIANCE $ Incr/(Decr)	VARIANCE % Fcst
GROSS CAPITAL	31,683	29,714	1,969	107 %
CONTRIBUTED CAPITAL	(15,025)	(15,682)	657	96 %
NET CAPITAL	**16,658**	**14,033**	**2,626**	**119 %**
BUILDINGS	232	805	(573)	29 %
LAND RIGHTS	223	—	223	— %
SUBSTATION EQUIPMENT	1,295	1,283	12	101 %
U/G PROJECTS	2,182	3,199	(1,017)	68 %
O/H PROJECTS	7,912	3,212	4,700	246 %
TRANSFORMERS	812	1,164	(353)	70 %
METERS	1,626	1,946	(321)	84 %
ROLLING STOCK	950	410	540	232 %
TOOLS	20	29	(9)	68 %
COMPUTER HARDWARE/SOFTWARE	652	1,248	(596)	52 %
OFFICE EQUIPMENT	20	—	20	— %
SUB TOTAL	**15,923**	**13,298**	**2,626**	**120 %**
DEVELOPER BUYBACKS	735	735	—	100 %
TOTAL CAPITAL EXPENDITURES	**16,658**	**14,033**	**2,626**	**119 %**

- **Net Capital Expenditures** are forecast to be **$2,626k** higher than the 2024 forecast driven by:
  - Land Rights $223k - Includes the 10-year true-up of the Hydro One Tremaine TS CCRA and the final true-up of the Hydro One Bronte TS CCRA;
  - O/H projects $4,700k – Primarily due to the Dundas Road Widening project (Guelph line to Kerns Rd.), which was delayed from 2024 and is now expected to be completed in 2025; partly offset by lower expenditures for pole replacements and general service projects;
  - Rolling Stock $540k - 2025 includes the purchase of a body and chassis for two bucket trucks, and an additional small vehicle.

  partly offset by the following decreases:

  - Buildings $(573)k - 2024 included expenditures for replacement/refurbishment of the receiving dock, and construction of a retaining wall in the yard. In addition, expenditures for roof replacement at 1340 Brant Street are expected to be lower than 2024;
  - U/G Projects $(1,017)k – Expenditures are forecasted to return to historical levels for underground cables and general service projects - 2024 expenditures included a large number of reactive replacements;
  - Transformers $(353)k - transformer replacements are expected to return to historical levels - 2024 included the replacement of leaky/faulty transformers;
  - Meters $(321)k - No further expenditures are planned for the Burlington TS metering project, which is expected to be completed in 2024; partially offset by higher demand for suite metering projects; and
  - Computer Hardware/Software $(596)k – 2024 included the implementation of the new OMS which is expected to be completed in 2024.

- **Contributed Capital** is forecast to be $657k lower than the 2024 forecast driven by:
    - o $6,175k - the Metrolinx GO Corridor Electrification project, contracted with Metrolinx, is expected to be completed in 2024;
    - o $884k - Expenditures on General service projects and the associated capital contributions are expected to lower in 2025;

  partly offset by the following increases:

    - o ($4,209k) - The Dundas Road Widening project (Guelph Line to Kerns Rd. and up to Northampton Blvd) is expected to be completed in 2025;
    - o ($2,204k) - Increased capital contributions as a result of a higher number of system expansion projects in the Downtown core area.

2026 Forecast

MANAGEMENT DISCUSSION & ANALYSIS (MD&A)

2026 Cost of Service Rate Application

Burlington Hydro is rebasing its rates in 2026 which is driving an increase in the revenue required to provide service to its customers. In addition to achieving BHI's strategic objectives, the increase in revenue requirement is required to address specific key capital and operational requirements.

- responding to evolving policy and customer expectations in response to the energy transition, such as connecting electric vehicles, solar panels, and energy storage;
- responding to increased demand in the City of Burlington due to electrification and population growth;
- ensuring a sustainable, resilient and reliable distribution system capable of accommodating more extreme weather events;
- addressing declining reliability, due to failure of aging infrastructure, through increased proactive replacements, asset testing and maintenance
- integrating cloud computing, artificial intelligence and non-wires solutions into operations;
- protecting customers' data and the grid against intensifying cyber security threats driven by rapid technology advancements and changing geopolitical dynamics;
- complying with new or expanded legal and regulatory requirements, including customer service, safety, and environmental obligations;
- addressing upward cost pressures on labour which are impacting outsourced services such as tree trimming and locates; and
- addressing a variety of externally-driven costs such as regulatory and insurance costs

The increase in revenue requirement is expected to result in a distribution rate increase of 25.1% and a total bill increase of 7.0% versus 2025 for an average residential customer. In addition to addressing specific key capital and operational requirements, the increase in distribution revenue is also driven by a change in the cost of capital parameters since BHI's last Cost of Service application.

Customer Engagement

As part of its 2026 Cost of Service application, BHI conducted an extensive customer engagement exercise as consisting of two phases, including soliciting feedback from customers on its major investments proposed for 2026 to 2030.

The iterative design of the Customer Engagement process was intended to enable BHI to first gain in-depth insight into the needs, values, interests, and priorities of its customers through the foundational Customer Interviews conducted in Phase I, which were incorporated into the business planning process. As BHI's plans were refined and the related spending and impacts on customer bills were developed further, broader customer feedback was sought from a larger sample of customers through a Web Survey and a Key Customer Webinar, conducted in Phase II. BHI has used this insight throughout its Business Planning process to ensure its Cost of Service application and 2026 financial plan are aligned with its customers.

In total, more than **3,500** residential, small commercial and large commercial/industrial customers across a diverse cross-section of the Burlington community participated in the Customer Engagement process.

The results of the engagement show that customers are aligned with BHI's strategic priorities of providing **safe** and **reliable** electricity at **prudent** rates. Tactical priorities that customers are most aligned with include proactively replacing deteriorated infrastructure, upgrading the distribution system to respond to increasing extreme weather, and investing in new and innovative technology to modernize the grid.

More than 90% of customers agreed that BHI's capital expenditure priorities are important, with more than 85% saying that the level of spending was appropriate. A subset of customers (<20%) indicated that the overall bill impact of BHI's proposed plan wasn't appropriate – BHI has incorporated this feedback into its plan through targeted reductions and re-pacing of expenditures to mitigate the overall bill impact.

Achieving BHI's strategic objectives, addressing specific key capital and operational requirements, and incorporating customer feedback informed the development of the business plan and financials for 2026.

BHI - 2026 BUDGET NET INCOME	2026 FORECAST	2025 BUDGET	VARIANCE $ F/(U)	VARIANCE % Fcst
DISTRIBUTION REVENUE	48,141	38,878	9,263	124 %
OTHER REVENUE	2,195	1,989	206	110 %
DEFERRED REVENUE	2,376	1,959	417	121 %
TOTAL REVENUE	**52,712**	**42,827**	**9,885**	**123 %**
OPERATIONS AND MAINTENANCE	13,703	12,795	(907)	107 %
BILLING AND CUSTOMER SERVICE	3,429	3,262	(167)	105 %
ADMIN INCL PROPERTY TAX	13,033	11,635	(1,398)	112 %
TOTAL OPERATING EXPENSES	**30,164**	**27,692**	(2,473)	**109 %**
DEPRECIATION	10,179	9,323	(856)	109 %
EARNINGS BEFORE INTEREST AND TAX	**12,369**	**5,812**	**6,557**	**213 %**
NET FINANCE COSTS	3,498	2,302	(1,196)	**152 %**
NET INCOME BEFORE TAXES	**8,871**	**3,510**	**5,361**	**253 %**
TOTAL TAXES	1,020	404	(616)	253 %
NET INCOME AFTER TAXES	**7,850**	**3,106**	**4,744**	**253 %**

Earnings Before Tax (EBT)

- EBT of **$8,871k** is expected to be **$5,361k** favorable vs. the 2025 Budget of $3,510k primarily due to:
  - favorable distribution revenue of **$9,263k** driven by the rebasing of rates in 2026;
  - favorable other revenue of **$206k** driven by
    - Management fees billed for Phase 2 of the Burloak Grade Separation project of $139k; and
    - higher late payment charges of $52k which are directly proportional to the increase in distribution revenue.
  - favorable deferred revenue of **$417k** driven by a full year of depreciation on 2025 additions, and an increase in contributed capital associated with Phase II of the Burloak Grade Separation project, the Dundas Road Widening Project (Appleby Line to Northhampton), and expansion costs associated with development at the Major Transit Station Areas.
    - Deferred Revenue reflects IFRS accounting treatment for the receipt of capital contributions for projects. Capital Contributions are received from customers for different capital projects consistent with BHI's Conditions of Service. Contributions

received are recorded on the Balance Sheet as both a PP&E asset and as a Deferred Revenue liability.

  - The Deferred Revenue Liability is amortized and recorded on the P&L as Miscellaneous Revenue over the life of the asset. The PP&E asset also is depreciated at the same rate with an equal and offsetting Depreciation Expense recorded on the P&L, resulting in no "bottom line" impact to the P&L

partly offset by

- unfavorable operating expenses **$(2,473)k** described in further detail below;
- unfavorable depreciation expense **$(856)k** due to a full year of depreciation on 2025 additions, and ½ year depreciation on 2026 additions, partly offset by assets which are expected to be fully depreciated at the end of 2025; and
- unfavorable net finance costs of **$(1,196)k** driven by higher interest on long term debt (the 2026 budget anticipates requiring an additional $10M in debt)

Distribution Revenue

- Distribution Revenues will be set on a Cost of Service basis for 2026. Revenues of $48,141k are expected to be $9,263k favorable vs. the 2025 Budget of $38,878k.

  <u>Consumption/Demand/Customer Forecasts</u>

  - BHI's forecast for 2026 energy (kWh), demand (kW) and # of customers is based on a comprehensive regression analysis as part of the requirements for its Cost of Service Application. Variables considered were weather, the economy, population growth, increased loads from electric vehicles and heating, and conservation and demand management.

  - Since distribution revenues are set on a Cost of Service basis in 2026, consumption, demand and customer count forecasts will only impact the rates that BHI is approved to charge. However, should the load forecast approved in BHI's rate application be different than actuals, BHI's distribution revenue will be affected (i.e. if actual counts and load are lower than approved, BHI will undercollect its revenue requirement).

  - Assumptions for 2026 are as follows:

    - Customer growth of 0.5% and 1.0% for residential and GS<50 customers respectively;
    - kWh increase for rate classes billed on consumption (small commercial, USL) due to economic growth, and additional EV and heating loads;
    - kW (demand) decrease of approximately 2% for large commercial customers. Although this class will experience growth due to the economy, EVs and electric heating, this consequent increase in demand is more than offset by conservation savings from energy efficiency programs which are currently geared toward large commercial customers
    - In general, a significant increase in load related to electrification of transit and heating is not expected to impact consumption and demand until post 2026.

Operating Expenses

- 9% overall increase vs. the 2025 Budget

- Payroll and Benefits Forecast Assumptions
  - 4.00% annual increase for non-union staff
  - 3.00% annual increase for union staff based on collective agreement
  - 16.5% increase vs. the 2025 Budget driven by Group Life 8%, LTD Benefits 5%, Extended Health Benefits 15%, Dental Benefits 16%

BHI's workforce is expected to undergo significant change as a result of the following:

- The Ontario energy sector is undergoing transformational change driven by growth, electrification, technological advancements, changing regulatory requirements, and evolving consumer expectations. These changes create both challenges and opportunities for BHI and the broader industry. Upskilling existing employees and creating new positions is required to meet anticipated growth and adapt to the changing environment.

- The importance of, and public focus on, sustainability, resilience, and reliability, especially in light of climate change, increases the pressure on BHI to be proactive in workforce planning. To meet future demands, BHI must ensure it has the capacity to innovate while maintaining and hardening its grid. Inadequate planning could lead to delays in grid modernization, service interruptions, and an inability to meet regulatory and government net-zero targets.

- These challenges are compounded by increasing work demands, driven in part by anticipated housing growth and the need to replace aging distribution infrastructure. Additionally, evolving customer expectations will require new roles focused on customer service and internal support.

In order to manage these changes effectively, BHI plans to hire 14 new positions in 2026 as identified in the table below, which are incorporated into the operating expenses for 2026.

Department	Position	Purpose
Accounting	Financial Analyst	Energy Transition, Growth, Grid Modernization
Control Room	Apprentice	Succession Planning, growth
Engineering	Supervisor, Energy Transition Integration	Energy Transition
	Supervisor, GIS	Replacement for redeployment to IT
	Supervisor, Planning & Grid Modernization	Growth, Grid Modernization
	Operations Clerk	Growth, Grid Modernization
	GIS Technician	Replacement for redeployment to IT
	Engineering Technician	Energy Transition, Growth
	Engineering Technician	Energy Transition, Growth
HR	HR Analyst/Generalist	Organizational Growth
Metering	Apprentice	Energy Transition, Growth
Regulatory	Regulatory Analyst	Energy Transition, Growth, Grid Modernization
	Senior Mgr, Capital Planning & Supply Chain	Energy Transition, Growth, Grid Modernization
Safety	Facilities Specialist/Coordinator	Organizational Growth, Building Maintenance

- Operations & Maintenance (Control Room /Stations /Meter Shop/ Distribution (Lines)) costs are forecast to be unfavorable vs. the 2025 Budget by **$(907)k** due to:
  - $(1,195)k increase in salaries and wages due to inflation, the hiring of two apprentices in each of the control room and metering, and the hiring of seven employees in engineering; partly offset by
  - $300k in licensing and support costs for operational technology, transferred from engineering to the information technology department to centralize processes; and
  - $72k in metering reading costs - savings were realized due to consolidation of ITRON interval meter services into BHI's settlement services with Utilismart.

- Billing & Collecting (Billing Department, Call Centre, Meter Reading) costs are forecast to be **$(167)k** unfavorable vs. the 2025 Budget primarily due to inflationary increases in salaries and benefits

- Administration Department (Executive, Human Resources, IT, Purchasing, Regulatory, Safety, Communications, Accounting, Board of Directors) costs are forecast to be unfavorable vs. the 2025 Budget by **$(1,398)k** due to:

  - $(964)k in salaries, benefits and temporary staff due to inflation and the addition of five full time staff across the Accounting, HR, Regulatory and Safety departments;
  - $(111)k bonus payments due to an increase in the number of eligible employees;
  - $(363)k in information and technology costs, $300k of which were transferred from the engineering department. The remaining $54k increase is related to software support and maintenance for OMS;
  - $(54k) for training costs associated with a higher number of employees and additional requirements; and
  - $(79)k for other expenses including communications, insurance, and OEB costs; partly offset by
  - $229k lower costs associated with rate rebasing for studies and consultants in preparation for the 2026 Cost of Service - the majority of these costs will be incurred in 2024 and 2025.

Capital Expenditures

BHI - 2026 BUDGET CAPITAL EXPENDITURES	2026 FORECAST	2025 BUDGET	VARIANCE $ Incr/(Decr)	% Fcst
GROSS CAPITAL	43,648	31,683	11,965	138 %
CONTRIBUTED CAPITAL	(21,560)	(15,025)	(6,535)	143 %
NET CAPITAL	**22,088**	**16,658**	**5,430**	**133 %**
BUILDINGS	856	232	624	369 %
LAND RIGHTS	—	223	(223)	— %
SUBSTATION EQUIPMENT	1,545	1,295	250	119 %
U/G PROJECTS	4,723	2,182	2,541	216 %
O/H PROJECTS	7,463	7,912	(449)	94 %
TRANSFORMERS	828	812	16	102 %
METERS	4,199	1,626	2,573	258 %
ROLLING STOCK	1,031	950	81	109 %
TOOLS	20	20	—	102 %
COMPUTER HARDWARE/SOFTWARE	652	652	—	100 %
OFFICE EQUIPMENT	20	20	—	102 %
SUB TOTAL	**21,338**	**15,923**	**5,415**	**134 %**
DEVELOPER BUYBACKS	750	735	15	102 %
TOTAL CAPITAL EXPENDITURES	**22,088**	**16,658**	**5,430**	**133 %**

- **Net Capital Expenditures** are forecast to be **$5,430k** higher than the 2025 Budget driven by:
    - Buildings $624k - 2026 includes (i) replacement/refurbishment of sections of its roof at 1340 Brant Street that are beyond economic repair, (ii) fence replacement/hardening to enhance security in the yard, (iii) expansion and paving of the parking lot south of BHI's head office; and (iv) expansion study for the vacant land south of BHI's head office.
    - Substation Equipment $250k - Increased replacement of number of Relays based on the BHI's Asset Condition Assessment (ACA) and higher expenditures for Circuit breakers replacements due to an increase in unit cost replacement;
    - U/G Projects $2,541k – Increased replacement of Underground cables based on BHI's ACA; and expansion costs for development of the Major Transit Station Areas (Burlington GO);
    - Meters $2,573k- Replacement of smart meters reaching the end-of-life as required by Measurement Canada; and replacement of BHI's AMI Collector System;

    partly offset by the following decreases:

    - Land Rights $(223)k - 2025 included expenditures for the 10-year true-up for the Tremaine TS CCRA and the final true-up of the Bronte TS CCRA in 2025;
    - O/H Projects $(449)k – Major work on the Dundas Road widening project is expected to be completed in 2025, partially offset by (i) higher expenditures for pole replacements and (ii) expenditures for expansion costs for development of the Major Transit Station Areas (Aldershot and Burlington GO).

- **Contributed Capital** is forecast to be $(6,535)k higher than the 2025 Budget driven by:
    - $(3,269)k - Capital contributions received for the Dundas Rd Widening project;
    - $(4,998)k - Capital contributions received from developers for expansion costs associated with the development of Major Transit Station Areas (Aldershot and Burlington GO);
    - $(856)k - Capital contributions received for Phase II of the Burloak Grade Separation project.

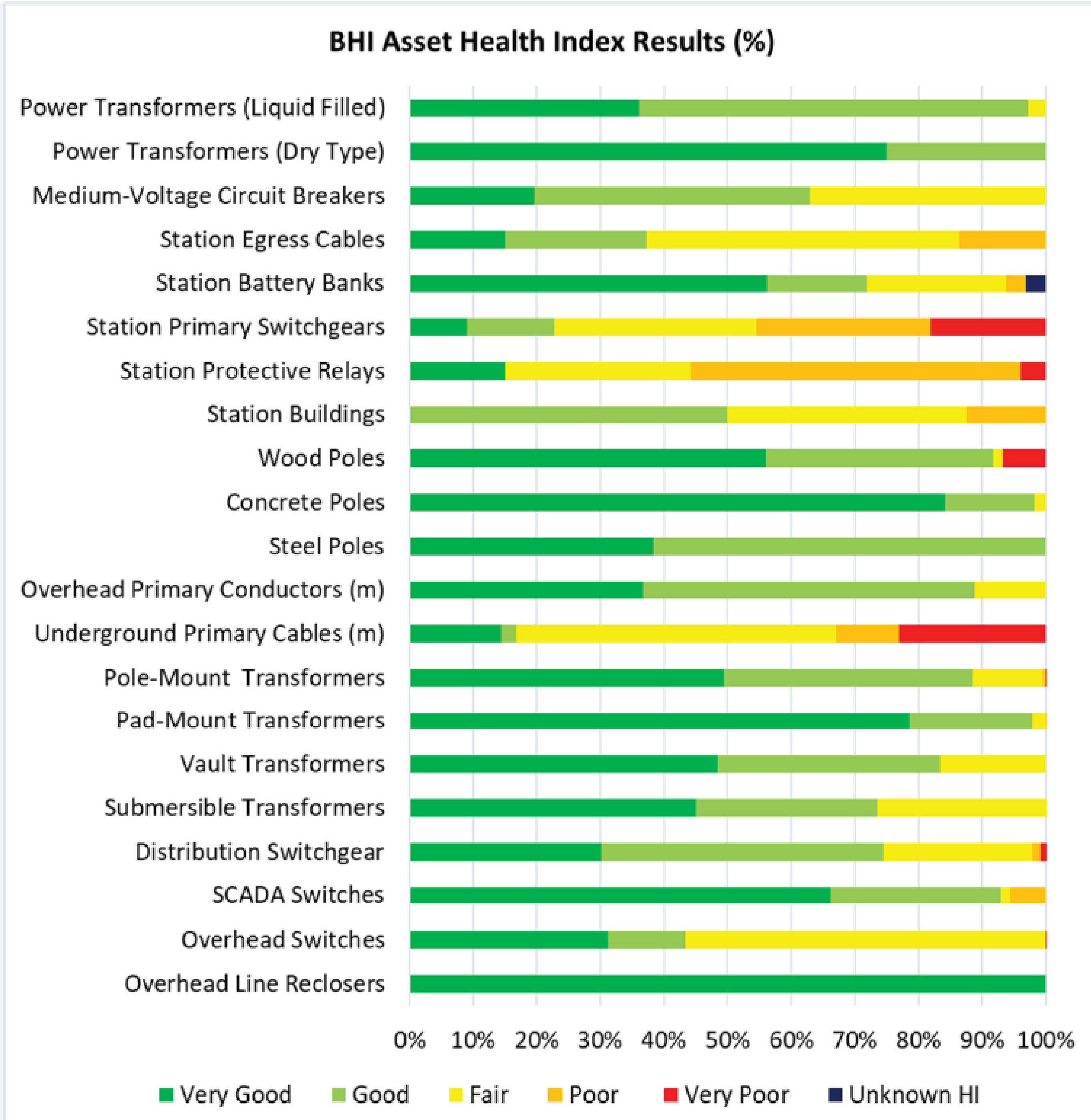
These increases are partly offset by the expected completion of projects in the Downtown core area in 2025 of $2,248k.

BHI is required to file a Distribution System Plan, including a forecast of capital expenditures from 2026-2030, as part of its 2026 Cost of Service Rate Application. BHI's capital expenditure forecast is provided below.

BHI - 2025-2030 CAPITAL EXPENDITURES	2024 FCST	2025 BUDGET	2026 FCST	2027 FCST	2028 FCST	2029 FCST	2030 FCST
GROSS CAPITAL	29,714	31,683	43,648	33,428	34,904	25,872	24,842
CONTRIBUTED CAPITAL	(15,682)	(15,025)	(21,560)	(10,997)	(15,709)	(9,095)	(9,280)
NET CAPITAL	**14,033**	**16,658**	**22,088**	**22,431**	**19,195**	**16,777**	**15,562**
BUILDINGS	805	232	856	545	584	335	298
SUBSTATION EQUIPMENT	1,283	1,295	1,545	1,524	1,554	1,585	1,617
U/G PROJECTS	3,199	2,182	4,723	4,337	3,899	3,652	3,395
O/H PROJECTS	3,212	7,912	7,463	5,133	5,358	5,248	5,575
TRANSFORMERS	1,164	812	828	843	860	877	895
METERS	1,946	1,626	4,199	4,161	3,894	2,095	2,109
ROLLING STOCK	410	950	1,031	911	745	685	267
TOOLS	29	20	20	21	21	22	22
COMPUTER HARDWARE/SOFTWARE	1,248	652	652	4,182	1,508	1,500	575
OFFICE EQUIPMENT	—	20	20	47	29	22	35
SUB TOTAL	**13,298**	**15,923**	**21,338**	**21,703**	**18,453**	**16,020**	**14,789**
DEVELOPER BUYBACKS	735	735	750	728	743	757	773
TOTAL CAPITAL EXPENDITURES	**14,033**	**16,658**	**22,088**	**22,431**	**19,195**	**16,777**	**15,562**

BHI's Distribution System Plan for 2026-2030 is focused on achieving key strategic objectives in safety, customer value, reliability, technology, and efficiency.

BHI's replacement programs are informed by the condition of its assets as determined by an ACA conducted as part of its Distribution System Plan. An ACA collects condition data on each of its assets, and based on that data determines the health index of each asset which in turn categorizes that asset into health categories.The DSP addresses those assets in poor/very poor condition (which may require replacement in the 5-year DSP term), namely, station switchgears, relays, wood poles, and underground primary cables.


BHI Asset Health Index Results (%)
Power Transformers (Liquid Filled)
Power Transformers (Dry Type)
Medium-Voltage Circuit Breakers
Station Egress Cables
Station Battery Banks
Station Primary Switchgears
Station Protective Relays
Station Buildings
Wood Poles
Concrete Poles
Steel Poles
Overhead Primary Conductors (m)
Underground Primary Cables (m)
Pole-Mount Transformers
Pad-Mount Transformers
Vault Transformers
Submersible Transformers
Distribution Switchgear
SCADA Switches
Overhead Switches
Overhead Line Reclosers
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Very Good
Good
Fair
Poor
Very Poor
Unknown HI

Variances in expenditures over the 5-year DSP term are primarily driven by:

- **Buildings** - BHI plans to invest in roof replacements or refurbishments for areas beyond economic repair between 2026 and 2028. Yard security will be enhanced in 2026 with the replacement and reinforcement of fences. Parking lot expansions and refurbishment will commence in 2026 south of BHI's head office and in 2027 and 2028 north of BHI's head office.
- **Substation, Underground, and Overhead projects** - BHI's recent Asset Condition Assessment (ACA), identified a number of asset categories with a material number of their population in poor or very poor condition, specifically: Switchgear, Relays, Poles, and Underground cables. BHI plans to increase spending on proactive replacement of these assets from 2026 to 2030. Additional expenditures are also expected for expansions associated with the development of Major Transit Stations Areas. These increases are more than offset by the completion of the Dundas Road road widening project in 2026.
- **Meters -** BHI is planning a phased replacement of its smart meters over 2026 to 2028 to comply with Measurement Canada regulations. These meters were installed in 2001 as part of the Smart Meter initiative and are due for replacement.
- **Computer Hardware/Software** - In 2027, BHI plans to replace its SCADA system and install an Advanced Distribution Management System (ADMS) which will support predictive and autonomous operations, automate outage restoration and support an optimized distribution grid that accelerates the energy transition through facilitating adoption of microgrids and electric vehicles. In 2028/2029 BHI plans to replace its ERP.
- **Other** - BHI is planning to replace some of its large vehicle fleet in 2026 and 2027 and its ERP system over 2028-2029.

2025 and 2026 Dividends and Debt Structure

Dividends

BHI - 2025 BUDGET DIVIDENDS $000s	2024 Update	2025 Budget	2026 Forecast	2027 Forecast	2028 Forecast
31-MAR - TRUE-UP PRIOR YEAR	184	912	333	2,136	1,682
31-MAR - WORKING CAPITAL BEC	50	50	50	50	50
31-MAR - REGULAR PAYMENT	417	417	417	417	417
31-JUN - REGULAR PAYMENT	417	417	417	417	417
31-SEP - REGULAR PAYMENT	417	417	417	417	417
31-DEC - REGULAR PAYMENT	417	417	417	417	417
SUB-TOTAL REGULAR DIVIDENDS	**1,902**	**2,629**	**2,050**	**3,853**	**3,399**
SPECIAL DIVIDEND - CAP STUDY	58	—	—	—	—
SPECIAL DIVIDEND - FORESTRY LEASE	116	118	120	—	—
TOTAL DIVIDENDS	**2,076**	**2,747**	**2,170**	**3,853**	**3,399**

- Regular Dividends are forecast at $2,629k for 2025, which includes:
  - a forecasted $912k true-up payment for 2023 to result in a 50% payout on BEC consolidated net income
  - a $50k payment to provide BEC with working capital
  - regular 2025 dividend payments of $1,668k (BHI's portion of the $2M minimum payment to be made to the City of Burlington)
- Special Dividends are forecast at $118k for 2025 which represents:
  - $118K for the value of the 2025 property and trailer lease for the City of Burlington Forestry Group.
- Dividends related to 2025 results are expected to return to historical levels ($2M plus $50K in working capital for BEC). Due to the anticipated increase in distribution revenue as a result of the 2026 Cost of Service rate application, it is anticipated that dividend payments to BEC will start to increase beyond $2.4M beginning in 2027. Dividends forecast in the 2027-2034 fiscal years represent 50% of consolidated net income.

Long Term Debt

An additional $10M of long-term debt is planned for 2025. The facility is already in place with the TD Bank and is available for drawdown when required. This debt will be used to assist in financing the 2025 capital program. In addition, $10M of long-term debt is planned for 2026.

Shareholder Promissory Note

The 2025 budget uses a rate of 2.85% as was approved during the 2021 COS application. This is the approved deemed OEB long-term debt rate effective May 1, 2021. This rate will be reset during the 2026 Cost of Service rate application. The rate assumed for 2026-2034 is 4.58% based on the OEB's Cost of capital parameters for 2024 rate applications.

Short-term Debt with TD Bank

The budget includes the costs of maintaining a $20M operating line of credit for working capital needs and an $18M letter of credit facility to cover prudential requirements related to the monthly power bill with the IESO.

Leverage and Cash Flow

The OEB deemed debt/equity capital structure is set at 60%/40% of an LDC's approved rate base. BHI's approved rate base is $147M which would permit a debt position for rate setting purposes of $88M.

BHI's forecasted outstanding total debt at year end 2025 is $69M, which is within the OEB limit and also continues to provide flexibility to increase long-term borrowings as needed for both ongoing capital expenditures and in the event of a catastrophic event.

Lender covenants limit Total Debt/Total capital to 0.60. Total Debt/Total Capital forecasted at the end of 2025 is 0.41.

The 10-year time horizon forecasts additional borrowings of $10M until BHI's next rebasing application in 2026 (i.e. 2025) and $115M over the forecast period. BHI has capacity to increase its leverage to fund capital projects with a solid debt/capital structure. Forecasted borrowings over the 10-year time horizon maintain company leverage within lender covenants.

Burlington Hydro Inc.

2025 Business Plan

10-year Financial Statements

BURLINGTON HYDRO INC. BALANCE SHEET ($000s)	2024 Update	2025 Budget	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2031 Fcst	2032 Fcst	2033 Fcst	2034 Fcst
Current Assets											
Cash	4,554	2,926	1,040	589	2,159	4,869	3,163	2,959	2,759	1,966	684
Securities held as Customer Deposits	2,699	2,916	3,611	3,700	3,789	3,885	4,008	4,544	4,715	4,899	5,079
Accounts Receivable	19,897	20,385	21,537	21,988	22,444	22,917	23,428	24,430	25,012	25,617	26,225
Unbilled Revenue	19,275	19,748	20,864	21,301	21,743	22,201	22,696	23,666	24,230	24,816	25,406
Income Taxes Receivable	-	-	-	-	-	-	-	-	-	-	-
Inventory	5,606	5,874	6,018	6,167	6,314	6,475	6,680	7,573	7,858	8,165	8,465
Work Orders in Progress	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500	3,500
Prepaid Expenses	827	827	827	827	827	827	827	827	827	827	827
Total Current Assets	56,357	56,175	57,395	58,072	60,776	64,675	64,302	67,499	68,900	69,790	70,186
Net Property Plant & Equipment	224,937	247,297	280,766	303,200	326,364	340,022	352,243	363,152	372,693	386,991	401,481
Deferred Tax Assets	-	-	-	-	-	-	-	-	-	-	-
TOTAL ASSETS	281,294	303,472	338,161	361,272	387,140	404,697	416,545	430,651	441,594	456,781	471,667
Net Regulatory Asset Balances	12,003	10,202	8,869	8,869	8,869	8,869	8,869	8,869	8,869	8,869	8,869
TOTAL ASSETS & Regulatory Balances	293,297	313,674	347,030	370,141	396,009	413,566	425,414	439,520	450,463	465,650	480,536
Current Liabilities											
Current Portion of Long Term Debt	2,902	3,124	4,217	5,604	7,060	8,189	8,946	10,034	11,323	12,060	11,335
Accts Payable & Accrued Liabilities	29,417	30,270	31,138	31,823	32,523	33,240	33,973	34,724	35,492	36,278	37,082
Customer Deposits	2,699	2,916	3,611	3,700	3,789	3,885	4,008	4,544	4,715	4,899	5,079
Work Order Deposits	11,270	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Deferred Revenue - CDM Programs	-	-	-	-	-	-	-	-	-	-	-
Other Liabilities	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840	3,840
Total Current Liabilities	50,127	50,149	52,806	54,967	57,211	59,153	60,767	63,141	65,369	67,076	67,336
Deferred Revenue - Cap Contributions	74,489	87,554	106,739	115,172	128,031	134,141	140,298	144,189	148,137	157,071	166,049
Shareholder Note Payable	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879
Long Term Debt	11,336	18,213	23,995	33,391	41,331	48,143	49,196	49,163	47,840	45,779	44,444
Deferred Tax Liability	7,789	7,789	7,789	7,789	7,789	7,789	7,789	7,789	7,789	7,789	7,789
Liability for Future Benefits	3,596	3,650	3,702	3,754	3,806	3,858	3,910	3,962	4,014	4,066	4,118
TOTAL LIABILITIES	195,216	215,234	242,910	262,952	286,048	300,963	309,840	316,122	321,027	329,660	337,615
Equity											
Capital Stock	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139
Paid-up Capital	876	876	876	876	876	876	876	876	876	876	876
Retained Earnings	51,614	51,974	57,654	60,722	63,494	66,136	69,107	76,930	82,968	89,523	96,455
Accumulated Other Compr Income	452	452	452	452	452	452	452	452	452	452	452
TOTAL EQUITY	98,081	98,441	104,121	107,189	109,961	112,603	115,574	123,397	129,435	135,990	142,922
Net Regulatory Liability Balances	-	-	-	-	-	-	-	-	-	-	-
TOTAL LIABILITIES, EQUITY & Reg Balances	293,297	313,674	347,030	370,141	396,009	413,566	425,414	439,520	450,463	465,650	480,536

BURLINGTON HYDRO INC. STATEMENT OF Retained Earnings ($000'S)	2024 Update	2025 Budget	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2031 Fcst	2032 Fcst	2033 Fcst	2034 Fcst
Opening Retained Earnings	48,218	51,614	51,974	57,654	60,722	63,494	66,136	69,107	76,930	82,968	89,523
Net Income (loss)	5,472	3,106	7,850	6,921	6,171	5,682	5,780	10,726	11,451	12,330	13,147
Dividends	(2,076)	(2,747)	(2,170)	(3,853)	(3,399)	(3,040)	(2,809)	(2,903)	(5,413)	(5,776)	(6,215)
Closing Retained Earnings	51,614	51,974	57,654	60,722	63,494	66,136	69,107	76,930	82,968	89,523	96,455

RATIO ANALYSIS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Debt/Total Capital - TD Covenant .6	38.8%	41.3%	42.2%	44.8%	46.7%	48.1%	47.8%	46.5%	45.3%	43.7%	42.0%
Debt to Total Assets - IO Covenant .6	22.1%	22.8%	22.5%	24.0%	24.9%	25.8%	25.5%	24.9%	24.2%	23.1%	22.0%
Current Ratio	1.12	1.12	1.09	1.06	1.06	1.09	1.06	1.07	1.05	1.04	1.04
Interest Coverage	8.2	6.2	6.3	5.5	5.0	4.6	4.6	5.7	5.9	6.1	6.5
Debt Service Coverage - TD/IO Covenant 1.3	3.3	2.7	2.9	2.3	2.0	1.8	1.7	2.0	1.9	1.9	2.1

BURLINGTON HYDRO INC. STATEMENT OF CASH FLOWS ($000s)	2024 Update	2025 Budget	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2031 Fcst	2032 Fcst	2033 Fcst	2034 Fcst
Operating Activities											
Net Income after Taxes	5,472	3,106	7,850	6,921	6,171	5,682	5,780	10,726	11,451	12,330	13,147
Depreciation	8,688	9,323	10,179	10,994	11,740	12,214	12,622	13,023	13,361	13,798	14,243
Deferred Revenue Amortization	(1,598)	(1,959)	(2,376)	(2,563)	(2,850)	(2,986)	(3,123)	(3,209)	(3,297)	(3,496)	(3,696)
	12,562	10,470	15,653	15,352	15,062	14,910	15,279	20,539	21,515	22,632	23,694
Non-Cash Working Capital Changes											
Change in A/R	5,956	(488)	(1,152)	(451)	(456)	(473)	(511)	(1,001)	(582)	(605)	(608)
Change in Unbilled Revenue	285	(473)	(1,116)	(437)	(442)	(458)	(495)	(970)	(564)	(586)	(589)
Change in Inventory	(120)	(268)	(144)	(150)	(147)	(161)	(205)	(893)	(285)	(307)	(300)
Change in WIP	62	-	-	-	-	-	-	-	-	-	-
Change in A/P & Accrued Liabilities	(3,887)	853	868	685	700	717	733	751	768	786	804
Change in W/O Deposits	(1,117)	(1,270)	-	-	-	-	-	-	-	-	-
Change in Deferred Revenue	(1,336)	-	-	-	-	-	-	-	-	-	-
Change in Liability for Future Benefits	5	54	52	52	52	52	52	52	52	52	52
Change in Regulatory Balances	4,501	1,801	1,333	-	-	-	-	-	-	-	-
	4,976	209	(158)	(302)	(293)	(323)	(425)	(2,063)	(610)	(661)	(642)
Operating Cash Flow	17,539	10,679	15,496	15,050	14,768	14,586	14,854	18,477	20,905	21,971	23,052
Investing Activities											
Net Additions to PP&E	14,033	16,658	22,088	22,431	19,195	16,777	15,562	16,832	15,658	15,666	16,059
Additions to PP&E (from CC)	15,682	15,025	21,560	10,997	15,709	9,095	9,280	7,100	7,245	12,430	12,674
Net Cash Used for Investing Activities	29,714	31,683	43,648	33,428	34,904	25,872	24,842	23,932	22,903	28,096	28,733
Financing Activities											
Change in Securities Held as Customer Deposits	(51)	(217)	(695)	(90)	(88)	(96)	(123)	(536)	(171)	(184)	(180)
Change in Customer Deposits	51	217	695	90	88	96	123	536	171	184	180
Change in Current Portion of L-T Debt	821	222	1,094	1,387	1,455	1,129	758	1,087	1,289	737	(725)
Change in L-T Debt	(2,944)	6,876	5,783	9,396	7,940	6,811	1,054	(34)	(1,323)	(2,060)	(1,335)
Change in S/H Note Payable	-	(0)	0	-	-	-	-	-	-	-	-
Deferred Revenue	15,682	15,025	21,560	10,997	15,709	9,095	9,280	7,100	7,245	12,430	12,674
Net Cash Provided by Financing Activities	13,559	22,122	28,437	21,780	25,105	17,035	11,091	8,154	7,211	11,107	10,614
Increase (decrease) in Cash & Cash Equivalents	1,383	1,119	284	3,402	4,969	5,750	1,103	2,698	5,213	4,982	4,933
Cash & Cash Equivalents, Beginning of Year	5,246	4,554	2,926	1,040	589	2,159	4,869	3,163	2,959	2,759	1,966
Dividends Paid to BEC	(2,076)	(2,747)	(2,170)	(3,853)	(3,399)	(3,040)	(2,809)	(2,903)	(5,413)	(5,776)	(6,215)
Cash & Cash Equivalents, End of Year	4,554	2,926	1,040	589	2,159	4,869	3,163	2,959	2,759	1,966	684

BURLINGTON HYDRO INC. **STATEMENT of COMPREHENSIVE INCOME ($000s)**	**2024** **Update**	**2025** **Budget**	**2026** **Fcst**	**2027** **Fcst**	**2028** **Fcst**	**2029** **Fcst**	**2030** **Fcst**	**2031** **Fcst**	**2032** **Fcst**	**2033** **Fcst**	**2034** **Fcst**	**2024** **Budget**
TOTAL REVENUE	226,946	232,515	245,651	250,799	256,004	261,400	267,229	278,652	285,290	292,194	299,134	231,952
-: Cost of Power Purchased	189,840	193,637	197,510	201,460	205,489	209,599	213,791	218,067	222,428	226,877	231,415	195,132
DISTRIBUTION REVENUE	37,106	38,878	48,141	49,339	50,515	51,801	53,438	60,585	62,862	65,317	67,719	36,820
Other Operating Revenue												
Late Payment Charges	210	217	269	275	282	289	298	338	351	365	378	220
Carrying Charges on Regulatory Balances	378	100	100	100	100	100	100	100	100	100	100	100
BESI Billing Service Revenue	452	489	501	513	524	536	548	560	572	584	596	451
Deferred Revenue - amort. of Contr.Capital	1,598	1,959	2,376	2,563	2,850	2,986	3,123	3,209	3,297	3,496	3,696	1,810
Miscellaneous	1,818	1,183	1,325	1,333	1,342	1,353	1,372	1,396	1,424	1,455	1,483	993
	4,456	3,948	4,571	4,784	5,098	5,264	5,441	5,603	5,744	6,000	6,253	3,574
Operating Expenses												
Operations & Maintenance	11,625	12,795	13,703	14,182	14,679	15,192	15,724	16,275	16,844	17,434	18,044	11,524
Billing & Collection	3,065	3,262	3,429	3,549	3,673	3,802	3,935	4,072	4,215	4,362	4,515	3,119
General Administration	10,220	11,286	12,673	13,117	13,576	14,051	14,543	15,052	15,579	16,124	16,689	9,685
Municipal Tax	339	349	359	372	385	398	412	427	442	457	473	372
Depreciation & Amortization	8,688	9,323	10,179	10,994	11,740	12,214	12,622	13,023	13,361	13,798	14,243	8,966
TOTAL EXPENSES	33,937	37,014	40,343	42,214	44,053	45,657	47,236	48,849	50,441	52,176	53,964	33,665
INCOME FROM OPERATING ACTIVITIES	7,625	5,812	12,369	11,909	11,561	11,408	11,643	17,340	18,165	19,141	20,009	6,728
Interest Expense - short term debt	72	72	72	72	72	72	72	72	72	72	72	72
Interest Expense - long term debt	551	989	1,342	1,914	2,424	2,864	2,999	3,082	3,117	3,092	3,013	856
Interest Expense - Shareholder Note	1,365	1,365	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	2,193	1,365
Interest Expense	1,988	2,425	3,607	4,179	4,688	5,129	5,264	5,347	5,382	5,357	5,278	2,293
Interest Income	546	123	109	90	101	141	152	127	156	148	125	153
Net Finance Costs	1,442	2,302	3,498	4,089	4,587	4,988	5,112	5,221	5,226	5,209	5,153	2,140
INCOME BEFORE INCOME TAXES	6,183	3,510	8,871	7,820	6,973	6,420	6,531	12,119	12,939	13,932	14,855	4,588
Income Taxes	711	404	1,020	899	802	738	751	1,394	1,488	1,602	1,708	528
TOTAL COMPREHENSIVE INCOME	5,472	3,106	7,850	6,921	6,171	5,682	5,780	10,726	11,451	12,330	13,147	4,060

BURLINGTON HYDRO INC.	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2024
CAPITAL BUDGET ($000s)	Update	Budget	Fcst	Fcst	Fcst	Fcst	Fcst	Fcst	Fcst	Fcst	Fcst	Budget
NET CAPITAL BUDGET												
Buildings	805	232	839	524	550	310	270	405	255	255	255	195
Land Rights	-	-	-	-	-	-	-	-	-	-	-	-
H1 CCRA True-up (Tremaine & Bronte TS)	-	223	-	-	-	-	-	-	-	-	-	-
Tremaine TS Breakers	-	-	-	-	-	-	-	-	-	-	-	-
Substation Equipment	1,283	1,295	1,515	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,530
Projects - Overhead and Underground	6,411	10,094	11,948	9,106	8,725	8,225	8,125	8,325	8,225	7,925	7,925	6,486
Transformers	1,164	812	812	811	811	811	811	811	811	811	811	811
Meters	1,946	1,626	4,117	4,001	3,670	1,936	1,910	2,501	1,549	1,563	1,577	1,826
Rolling Stock	410	950	1,011	876	702	633	242	227	162	187	237	455
Tools	29	20	20	20	20	20	20	20	20	20	20	20
Computer Hardware/Software	1,248	652	639	4,021	1,421	1,386	521	467	421	421	421	1,132
Office Equipment	-	20	20	45	28	20	32	28	20	20	28	20
	13,298	15,923	20,920	20,869	17,392	14,806	13,396	14,249	12,928	12,667	12,738	12,475
Developer Asset BuyBacks	735	735	735	700	700	700	700	700	700	700	700	450
NET CAPITAL BUDGET	14,033	16,658	21,655	21,569	18,092	15,506	14,096	14,949	13,628	13,367	13,438	12,925
CAPITAL CONTRIBUTIONS												
General Service Projects	13,682	13,025	19,137	8,574	12,806	6,406	6,406	4,306	4,306	8,606	8,606	14,374
Developer Assets Assumed	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
CAPITAL CONTRIBUTIONS	15,682	15,025	21,137	10,574	14,806	8,406	8,406	6,306	6,306	10,606	10,606	16,374
TOTAL CAPITAL BUDGET	29,714	31,683	42,792	32,142	32,898	23,912	22,502	21,254	19,934	23,973	24,044	29,299
INFLATION ADJUSTED CAPITAL BUDGET												
Sustaining Capital Budget Inflation Adj.	14,033	16,658	22,088	22,431	19,195	16,777	15,562	16,832	15,658	15,666	16,059	12,925
Capital Contributions Inflation Adj.	15,682	15,025	21,560	10,997	15,709	9,095	9,280	7,100	7,245	12,430	12,674	16,374
TOTAL INFLATION ADJ. CAPITAL BUDGET	29,714	31,683	43,648	33,428	34,904	25,872	24,842	23,932	22,903	28,096	28,733	29,299

BURLINGTON HYDRO INC. DIVIDENDS ($000's)	2024 Update	2025 Budget	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2031 Fcst	2032 Fcst	2033 Fcst	2034 Fcst
31-Mar True-up Prior Year	184	912	333	2,136	1,682	1,323	1,093	1,186	3,696	4,059	4,498
31-Mar Working Capital for BEC	50	50	50	50	50	50	50	50	50	50	50
31-Mar - Regular Payment	417	417	417	417	417	417	417	417	417	417	417
30-Jun - Regular Payment	417	417	417	417	417	417	417	417	417	417	417
30-Sep - Regular Payment	417	417	417	417	417	417	417	417	417	417	417
31-Dec - Regular Payment	417	417	417	417	417	417	417	417	417	417	417
Sub-Total Regular Dividends	**1,902**	**2,629**	**2,050**	**3,853**	**3,399**	**3,040**	**2,809**	**2,903**	**5,413**	**5,776**	**6,215**
Special Dividend	-	-	-	-	-	-	-	-	-	-	-
Cap Study - Special Dividend	58	-	-	-	-	-	-	-	-	-	-
Forestry Lease - Special Dividend	116	118	120	-	-	-	-	-	-	-	-
Total Dividends Declared/Paid to BEC	**2,076**	**2,747**	**2,170**	**3,853**	**3,399**	**3,040**	**2,809**	**2,903**	**5,413**	**5,776**	**6,215**