



Burlingtonhydro inc.

Registrar
Ontario Energy Board
27th Floor
2300 Yonge Street
Toronto, ON
M4P 1E4

September 19, 2025

Dear Mr. Murray,

**Re: OEB File No. EB-2025-0051, Burlington Hydro Inc. ("BHI")
2026 Cost of Service Application for Electricity Distribution Rates
Settlement Proposal**

Please find attached BHI's Settlement Proposal for its 2026 Cost of Service Application EB-2025-0051, pursuant to Procedural Order No. 2.

A Settlement Conference was held from August 11 to 14, 2025 in which BHI and the following 7 intervenors participated:

- Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)
- Consumers Council of Canada (CCC)
- Distributed Resource Coalition (DRC)
- Environmental Defence (ED)
- Pollution Probe (PP)
- School Energy Coalition (SEC)
- Vulnerable Energy Consumers Coalition (VECC)

The filed documents include:

- Settlement Proposal, which includes:
 - Appendix A: Settlement Commitments
 - Appendix B: Proposed Tariff of Rates and Charges
 - Appendix C: Accounting Orders
 - Appendix D: Responses to Pre-Settlement Conference Clarification Questions
- Live Excel models in support of the Settlement Proposal

Respectfully submitted,

Adam Pappas
Director, Regulatory Affairs, Supply Chain and Capital Planning
Email: apappas@burlingtonhydro.com
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IN THE MATTER OF the *Ontario Energy Board Act*,
1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Burlington
Hydro Inc. for an order approving just and reasonable rates
and other charges for electricity distribution beginning
January 1, 2026.

BURLINGTON HYDRO INC.

SETTLEMENT PROPOSAL

September 19, 2025

**Burlington Hydro Inc.
EB-2025-0051
Settlement Proposal**

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APPENDICES

Appendix A: Settlement Commitments

Appendix B: Proposed Tariff of Rates and Charges

Appendix C: Accounting Orders

Appendix D: Pre-Settlement Conference Clarification Questions

LIVE EXCEL MODELS

In addition to the Appendices listed above, the following live Excel models have been filed together with and form an integral part of this Settlement Proposal:

Settlement_Attachment_OEB_Chapter2Appendices_BHI
Settlement_Attachment_Load_Forecast_Model_BHI
Settlement_Attachment_2025_RRWF_BHI
Settlement_Attachment_2026_PILS_Workform_BHI
Settlement_Attachment_DVA_Continuity_Schedule_BHI
Settlement_Attachment_2026_Cost Allocation Model_v1.0_BHI
Settlement_Attachment_2026_RTSR_Workform_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI
Settlement_Attachment_Benchmarking_Spreadsheet_Forecast_Model_BHI
Settlement_Attachment_2026_ACM_ICM_Model_BHI

Burlington Hydro Inc.
EB-2025-0051
Settlement Proposal

Filed with OEB: September 19, 2025

Burlington Hydro Inc. (the “**Applicant**” or “**BHI**”) filed a Cost of Service application with the Ontario Energy Board (the “**OEB**”) on April 16, 2025 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B) (the “**Act**”) seeking approval for changes to the rates that BHI charges for electricity distribution and other charges, to be effective January 1, 2025 (OEB Docket Number EB-2025-0051) (the “**Application**”).

The OEB issued and published a Notice of Hearing dated May 8, 2025, and Procedural Order No. 1 on June 4, 2025, the latter of which required the parties to the proceeding to develop a proposed Issues List by June 10, 2025 and scheduled a Settlement Conference for July 24, 25 and 28 2025.

On June 11, 2025, Ontario Energy Board staff (“**OEB Staff**”) submitted a proposed Issues List as agreed to by the parties. On June 19, 2025, the OEB issued its Decision on the proposed Issues List and Procedural Order No. 2, approving the list submitted by OEB Staff (the “**Issues List**”) with the exception of two minor changes to wording of the proposed issues. And amended the schedule of the proceeding, which, among other things, changed the date of the Settlement Conference to August 11, 12, and 13, 2025.

BHI filed its Interrogatory Responses with the OEB on July 24, 2025, pursuant to which BHI updated several models and submitted them to the OEB as Excel documents.

A Settlement Conference was convened on August 11, 2025 and continued to August 14, 2025, in accordance with the OEB’s *Rules of Practice and Procedure* and the OEB’s *Practice Direction on Settlement Conferences* (the “**Practice Direction**”), which extended for an additional day beyond the timeline contemplated in Procedural Order No. 2.

Karen Wianecki acted as facilitator for the Settlement Conference which lasted for four days.

BHI and the following Intervenors, participated in the settlement conference:

- Coalition of Concerned Manufacturers and Businesses of Canada (“**CCMBC**”)
- Consumers Council of Canada (“**CCC**”)
- Distributed Resource Coalition (“**DRC**”)
- Environmental Defence Canada Inc. (“**ED**”)
- Pollution Probe (“**PP**”)
- School Energy Coalition (“**SEC**”)
- Vulnerable Energy Consumers Coalition (“**VECC**”)

The above Intervenor and Enbridge Gas Inc. (“**Enbridge**”) are collectively referred to as the “**Intervenor**”. BHI and the Intervenor, with the exception of Enbridge, are collectively referred to below as the “**Parties**”. Notwithstanding any other clause of this Settlement Proposal, Enbridge did not attend the Settlement Conference and was not a party to this Settlement, and takes no position with respect to, and does not oppose, any of the issues set out in the Issues List.

OEB Staff also participated in the Settlement Conference. The role adopted by OEB Staff is set out in page 5 of the Practice Direction. Although OEB Staff is not a party to this Settlement Proposal, as noted in the Practice Direction, OEB Staff who did participate in the Settlement Conference are bound by the same confidentiality requirements that apply to the Parties to the proceeding.

This document is called a “**Settlement Proposal**” because it is a proposal by the Parties to the OEB to settle the issues in this proceeding. It is termed a proposal as between the Parties and the OEB. However, as between the Parties, and subject only to the OEB’s approval of this Settlement Proposal, this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms. As set forth later in this Preamble, this Settlement Proposal is subject to a condition subsequent, that if it is not accepted by the OEB in its entirety, then unless amended by the Parties it is null and void and of no further effect. In entering into this Settlement Proposal, the Parties understand and agree that, pursuant to the Act, the OEB has exclusive jurisdiction with respect to the interpretation and enforcement of the terms hereof.

The Parties acknowledge that this settlement proceeding is confidential and privileged in accordance with the Practice Direction. The Parties understand that confidentiality in that context does not have the same meaning as confidentiality in the OEB’s Practice Direction, and the rules of that latter document do not apply. Instead, in this settlement conference, and in this Settlement Proposal, the Parties have interpreted “confidential” to mean that the documents and other information provided during the course of the settlement proceeding, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the settlement conference are strictly privileged and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception, being the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal. Further, the Parties shall not disclose those documents or other information to persons who were not attendees at the Settlement Conference. However, the Parties agree that “attendees” is deemed to include, in this context, persons who were not in attendance via video conference at the settlement conference but were (a) any persons or entities that the Parties engage to assist them with the settlement conference, and (b) any persons or entities from whom they seek instructions with respect to the negotiations; in each case provided that any such persons or entities have agreed to be bound by the same confidentiality provisions.

This Settlement Proposal provides a brief description of each of the settled issues, together with references to the evidence. The Parties agree that references to the “evidence” in this Settlement

Proposal shall, unless the context otherwise requires, include (a) additional information included by the Parties in this Settlement Proposal, (b) the Appendices to this document, and (c) the evidence filed concurrently with this Settlement Proposal titled “Responses to Pre-settlement Clarification Questions” (“**Clarification Questions**”). The supporting Parties for each settled issue agree that the evidence in respect of that settled issue is sufficient in the context of the overall settlement to support the proposed settlement, and the sum of the evidence in this proceeding provides an appropriate evidentiary record to support acceptance by the OEB of this Settlement Proposal.

There are Appendices to this Settlement Proposal which provide further support for the proposed settlement. The Parties acknowledge that the Appendices were prepared by BHI. While the Intervenor has reviewed the Appendices, the Intervenor is relying on the accuracy of those Appendices and the underlying evidence in entering into this Settlement Proposal.

Outlined below are the final positions of the Parties following the settlement conference. For ease of reference, this Settlement Proposal follows the format of the final approved issues list for the Application attached to the Issues List Decision and Procedural Order No. 2 dated June 19, 2025.

The Parties are pleased to advise the OEB that they have reached a complete agreement with respect to the settlement of all of the issues in this proceeding. Specifically:

“Complete Settlement” means an issue for which complete settlement was reached by all Parties, and if this Settlement Proposal is accepted by the OEB, the Parties will not adduce any evidence or argument during the oral hearing in respect of these issues.	# issues settled: # All
“Partial Settlement” means an issue for which there is partial settlement, as BHI and the Intervenor who take any position on the issue were able to agree on some, but not all, aspects of the particular issue. If this Settlement Proposal is accepted by the OEB, the Parties who take any position on the issue will only adduce evidence and argument during the hearing on those portions of the issues not addressed in this Settlement Proposal.	# issues partially settled: # None
“No Settlement” means an issue for which no settlement was reached. BHI and the Intervenor who take a position on the issue will adduce evidence and/or argument at the hearing on the issue.	# issues not settled: None

According to the Practice Direction (p. 3), the Parties must consider whether a Settlement Proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. These adjustments are specifically set out in the text of the Settlement Proposal.

The Parties have settled the issues as a package, and none of the parts of this Settlement Proposal are severable. If the OEB does not accept this Settlement Proposal in its entirety, then there is no settlement (unless the Parties agree in writing that any part(s) of this Settlement Proposal that the OEB does accept may continue as a valid settlement without inclusion of any part(s) that the OEB does not accept).

In the event that the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but no Party will be obligated to accept any proposed revision. The Parties agree that all of the Parties who took a position on a particular issue must agree with any revised Settlement Proposal as it relates to that issue, or decide to take no position on the issue, prior to its resubmission to the OEB.

Unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Proposal are without prejudice to the rights of Parties to raise the same issue and/or to take any position thereon in any other proceeding, whether or not BHI is a party to such proceeding.

Where in this Settlement Proposal, the Parties “accept” the evidence of BHI, or the Parties or any of them “agree” to a revised term or condition, including a revised budget or forecast, then unless the Settlement Proposal expressly states to the contrary, the words “for the purpose of settlement of the issues herein” shall be deemed to qualify that acceptance or agreement.

Summary

In reaching this complete settlement, the Parties have been guided by the current *Filing Requirements for Electricity Distribution Rate Applications* dated May 14, 2020, the *Handbook for Utility Rate Applications* dated October 13, 2016, the approved Issues List attached as to the OEB's Procedural Order No. 2 dated June 19, 2025, and the Report of the OEB titled *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* dated October 18, 2012.

This Settlement Proposal reflects a complete settlement of the issues in this proceeding.

Based on this Settlement Proposal, BHI has made changes to its 2026 Test year Revenue Requirement as identified in Table A below.

Table A – Summary of Revenue Requirement

Category	Description	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Cost of Capital	Regulated Return on Capital	\$11,445,947	\$11,401,653	(\$44,294)	\$11,091,448	(\$310,205)
	Regulated Rate of Return	6.20%	6.20%	0.00%	6.19%	-0.01%
Rate Base and Capital Expenditure	Rate Base	\$184,600,382	\$184,001,254	(\$599,127)	\$179,198,840	(\$4,802,414)
	Net Fixed Assets	\$168,957,808	\$168,444,817	(\$512,992)	\$163,672,833	(\$4,771,984)
	Working Capital Base	\$208,567,641	\$207,419,166	(\$1,148,475)	\$207,013,436	(\$405,730)
	Working Capital Allowance	\$15,642,573	\$15,556,437	(\$86,136)	\$15,526,008	(\$30,430)
	2026 Test Year Capital Expenditures	\$24,271,845	\$24,870,805	\$598,960	\$21,620,805	(\$3,250,000)
Operating Expenses	Depreciation Expense	\$10,046,886	\$10,065,714	\$18,828	\$9,652,371	(\$413,342)
	Taxes/PILs (Grossed up)	\$931,830	\$925,602	(\$6,228)	\$873,601	(\$52,001)
	OM&A (Excluding Property Taxes and Other Donations)	\$30,040,101	\$30,157,314	\$117,213	\$25,957,314	(\$4,200,000)
	Property Taxes	\$375,892	\$375,892	\$0	\$375,892	\$0
Revenue Requirement	Service Revenue Requirement	\$52,840,656	\$52,926,174	\$85,518	\$47,950,627	(\$4,975,547)
	Other Revenue	\$4,355,525	\$4,339,019	(\$16,506)	\$4,489,019	\$150,000
	Base Revenue Requirement	\$48,485,131	\$48,587,155	\$102,025	\$43,461,608	(\$5,125,547)
	Grossed Up Revenue Deficiency	\$10,070,403	\$10,237,984	\$167,581	\$4,672,360	(\$5,565,624)

The Bill impacts as a result of BHI's settlement proposal are identified in Table B below.

Table B – Bill Impacts

Class	kWh	kW	Distribution (Fixed and Volumetric)			
			Current Rates	Proposed Rates	\$ Change	% Impact
Residential	750		\$32.74	\$37.12	\$4.38	13.4%
GS<50 kW	1500		\$58.48	\$62.92	\$4.44	7.6%
GS<50 kW	2000		\$68.18	\$74.27	\$6.09	8.9%
GS>50 kW	36700	200	\$851.96	\$1,014.96	\$163.00	19.1%
Street Lighting	175	0.22	\$1.68	\$1.86	\$0.18	10.7%
Unmetered Scattered Load	2000		\$48.64	\$49.84	\$1.20	2.5%
Class	kWh	kW	Total Bill (after HST and OER)			
			Current Rates	Proposed Rates	\$ Change	% Impact
Residential	750		\$133.18	\$136.94	\$3.76	2.8%
GS<50 kW	1500		\$256.83	\$259.87	\$3.05	1.2%
GS<50 kW	2000		\$332.43	\$336.66	\$4.24	1.3%
GS>50 kW	36700	200	\$7,871.45	\$8,011.30	\$139.85	1.8%
Street Lighting	175	0.22	\$26.82	\$27.33	\$0.50	1.9%
Unmetered Scattered Load	2000		\$312.49	\$311.84	(\$0.65)	(0.2%)

The impact of the Settlement Proposal on BHI's cost performance and Stretch Factor Cohort is identified in Table C below.

Table C – Cost Benchmarking Results

Description	2023 Actuals	2024 Actuals	2025 Bridge Year	2026 Test Year
Actual Total Cost	\$59,075,631	\$61,448,092	\$61,937,821	\$69,368,744
Predicted Total Cost	\$65,280,800	\$68,773,780	\$66,887,700	\$74,982,827
Actual Cost Greater Than/(Less Than) Predicted Cost	(\$6,205,170)	(\$7,325,688)	(\$4,949,879)	(\$5,614,083)
Percentage Difference (Cost Performance)	-10.0%	-11.3%	-7.7%	-7.8%
Three-Year Average Performance	-11.7%	-11.6%	-9.6%	-8.9%
Stretch Factor Cohort - Annual	3	2	3	3
Stretch Factor Cohort - Annual (Three Year Average)	2	2	3	3

Based on the foregoing and the evidence and rationale provided below, the Parties agree that this Settlement Proposal is appropriate and recommend its acceptance by the OEB. Please refer to Appendix B for the Proposed Tariff of Rates and Charges resulting from the acceptance of this Settlement Proposal.

1. Capital Spending and Rate Base

1.1 Are the proposed capital expenditures and in-service additions appropriate?

Complete Settlement:

2026 Net Capital Expenditures and In-Service Additions: For the purposes of settlement, the Parties agree to reduce BHI's 2026 net capital expenditures and in-service additions by \$3.25M from \$24,870,805 as filed in OEB Appendices 2-AA and 2-AB of its interrogatory responses, resulting in 2026 Test Year capital expenditures of \$21,620,805. This reduction consists of the following amounts:

- (i) \$1.25M in respect of net capital expenditures and in-service additions other than those in the System Access investment category; and
- (ii) \$2.00M in respect of net capital expenditures and in-service additions for the System Access investment category, subject to the System Access Variance Account as set out below.

2026 System Access Variance Account: For the purpose of settlement, the Parties agree to establish an asymmetrical variance account ("System Access Variance Account") to record the revenue requirement associated with the difference between actual 2026 System Access capital additions and forecasted 2026 System Access capital additions in the Application, net of capital contributions. The baseline net capital additions used to determine any variance will be \$13,500,384. The account will be asymmetrical, such that (i) the maximum amount of additional 2026 System Access net capital additions used to calculate the revenue requirement recorded in the account will be limited to \$2M above the baseline, reflecting BHI's forecast budget in the application, while (ii) the revenue requirement impact of the aggregate amount of actual 2026 System Access net capital additions that are less than the baseline will be fully recorded in the account.

The Parties agree that BHI shall seek clearance of the System Access Variance Account as part of any Advanced Capital Module ("ACM") or Incremental Capital Module ("ICM") application that BHI may file during the IRM period, and if not, shall seek clearance at its next rebasing application. The Parties also agree that for the purposes of calculating any ACM or ICM materiality threshold for BHI during the IRM period, the 2026 rate base shall be deemed to include the \$2M maximum variance agreed upon by the Parties for the purposes of the System Access Variance Account regardless of the actual 2026 system access in-service additions.

Table 1.1A summarizes the capital expenditures by category for the 2026-2030 Distribution System Plan ("DSP") period. Since only the 2026 Test Year expenditures are being sought for approval in this proceeding, the revised Forecast Period (2027-2030) expenditures

included in Table 1.1A are being provided by the Applicant and are not meant to be construed as the Parties agreement that the amounts are appropriate.

Table 1.1A – Summary of Capital Expenditures by Category

Category	Forecast Period (planned)				
	2026	2027	2028	2029	2030
System Access	\$35,239,277	\$25,372,372	\$21,772,371	\$23,697,266	\$21,530,486
System Renewal	\$5,232,491	\$5,251,889	\$5,357,937	\$5,463,984	\$5,579,411
System Service	\$408,000	\$520,000	\$106,100	\$216,400	\$110,400
General Plant	\$2,439,129	\$3,008,934	\$5,435,191	\$2,587,285	\$1,089,875
Total Expenditure	\$43,318,898	\$34,153,195	\$32,671,599	\$31,964,935	\$28,310,172
Capital Contributions	(\$21,698,094)	(\$10,980,362)	(\$11,881,636)	(\$11,536,163)	(\$10,329,774)
Net Capital Expenditures	\$21,620,805	\$23,172,833	\$20,789,963	\$20,428,772	\$17,980,398
System O&M	\$11,333,633	\$0	\$0	\$0	\$0

Table 1.1B below identifies the changes in the 2026 Test Year gross and net capital expenditures from BHI's original Application to the Settlement proposal.

Table 1.1B – Capital Expenditures

Category	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
System Access	\$35,694,524	\$37,239,278	\$1,544,754	\$35,239,277	(\$2,000,000)
System Renewal	\$6,180,741	\$6,180,741	\$0	\$5,232,491	(\$948,250)
System Service	\$510,000	\$510,000	\$0	\$408,000	(\$102,000)
General Plant	\$2,594,880	\$2,638,880	\$44,000	\$2,439,129	(\$199,751)
Total Expenditure	\$44,980,145	\$46,568,899	\$1,588,754	\$43,318,898	(\$3,250,000)
Capital Contributions	(\$20,708,300)	(\$21,698,094)	(\$989,794)	(\$21,698,094)	\$0
Net Capital Expenditures	\$24,271,845	\$24,870,805	\$598,960	\$21,620,805	(\$3,250,000)

The Parties agree that the revised Test Year capital expenditures and additions, in conjunction with the newly established System Access Variance Account identified above, are reasonable. The Parties confirm that this level of spending is sufficient to maintain a safe and reliable distribution system and facilitate access for new connections and service upgrades.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including items nos. 1, 2, 4, 5 and 6.

Evidence:

Application:

Exhibit 1 Sections 1.2.4 C

Exhibit 2, inclusive of Appendix A (DSP)

IRs:

2-Staff-4, 2-Staff-5, 2-Staff-8, 2-Staff-9, 2-Staff-10, 2-Staff-12, 2-Staff-13, 2-Staff-14, 2-Staff-16, 2-Staff-17, 2-Staff-18, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 4-Staff-55, 4-Staff-59, 1-Intervenor-1, 1-Intervenor-2, 1-Intervenor-3, 1-Intervenor-4, 1-Intervenor-5, 1-Intervenor-6, 1-Intervenor-7, 1-Intervenor-8, 1-Intervenor-9, 1-Intervenor-11, 2-Intervenor-13, 2-Intervenor-14, 2-Intervenor-15, 2-Intervenor-16, 2-Intervenor-17, 2-Intervenor-30, 2-Intervenor-31, 2-Intervenor-32, 2-Intervenor-33, 2-Intervenor-34, 2-Intervenor-35, 2-Intervenor-36, 2-Intervenor-37, 2-Intervenor-38, 2-Intervenor-39, 2-Intervenor-40, 2-Intervenor-41, 2-Intervenor-42, 2-Intervenor-43, 2-Intervenor-45, 2-Intervenor-46, 2-Intervenor-47, 2-Intervenor-48, 2-Intervenor-49, 2-Intervenor-51, 2-Intervenor-52, 2-Intervenor-53, 2-Intervenor-54, 2-Intervenor-55, 2-Intervenor-56, 2-Intervenor-57, 2-Intervenor-58, 2-Intervenor-59, 2-Intervenor-60, 2-Intervenor-61, 2-Intervenor-62, 2-Intervenor-63, 2-Intervenor-64, 2-Intervenor-65, , 2, 2-Intervenor-66, 2-Intervenor-67, 2-Intervenor-68, 2-Intervenor-69, 2-Intervenor-70, 2-Intervenor-71, 2-Intervenor-72, , 2-Intervenor-73, 2-Intervenor-73, 2-Intervenor-74, 2-Intervenor-75, 2-Intervenor-76, 2-Intervenor-77, 2-Intervenor-78, 2-Intervenor-79, 2-Intervenor-80

Clarifying Question Responses:

Staff-96, Staff-97, Staff-102, Staff-103, Staff-104, ED-CQ-1, ED-CQ-2, ED-CQ-3, ED-CQ-4, ED-CQ-5, ED-CQ-6, ED-CQ-7, SC-CCC-3, SC-CCC-4, SC-CCC-6, SC-CCC-7, SEC-CQ-3, VECC-CQ-11

Appendices to this Settlement Proposal:

Appendix C: Accounting Orders

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

1.2 Are the proposed rate base and depreciation amounts appropriate?

Complete Settlement:

Subject to the modifications set out in this Issue 1.2 the Parties agree that the proposed rate base and depreciation amounts are appropriate:

- (a) Opening 2026 Rate Base: The Parties agree to reduce BHI's 2026 Test Year opening gross fixed assets by \$2.00M from \$363,271,627 as filed in OEB Appendix 2-BA of BHI's interrogatory responses to \$361,271,627.
- (b) 2026 Rate Base: The Parties agree to reduce BHI's 2026 Test Year net capital expenditures and in-service additions by \$3.25M based on the reductions to capital expenditures discussed in Issue 1.1.
- (c) Accumulated Depreciation: The Parties agree to increase the opening 2026 accumulated depreciation for USoA 1611 by \$1,372,768. The depreciation expense underpinning 2021 rates assumed a 20% depreciation rate for GIS and CIS assets. BHI calculated depreciation expense on its GIS and CIS assets using a 10% depreciation rate between 2022 and 2025. The Parties agree to adjust accumulated depreciation as if BHI had continued to depreciate the CIS and GIS assets, as approved in BHI's 2021 Cost of Service, using a 20% depreciation rate between 2022 and 2025. Table 1.2A identifies the changes in GIS and CIS depreciation as compared to that which was filed in BHI's original Application.

Table 1.2A – Adjustment to GIS and CIS Depreciation

Description	Application			Adjustment			Settlement Proposal		
	CIS	GIS	Total	CIS	GIS	Total	CIS	GIS	Total
2026 Opening Gross Assets	3,726,335	1,582,415	5,308,750	-	-	-	3,726,335	1,582,415	5,308,750
2026 Opening Accum Deprn	2,088,974	877,430	2,966,404	1,021,000	351,768	1,372,768	3,109,974	1,229,198	4,339,172
2026 Opening Net Book Value	1,637,361	704,985	2,342,346	(1,021,000)	(351,768)	(1,372,768)	616,361	353,217	969,578
2026 Depreciation on 2021 Additions	297,458	129,269	426,727	(210,386)	(72,487)	(282,873)	87,072	56,782	143,854
2026 Depreciation on 2022-2025 Additions	26,917	9,939	36,856	-	-	-	26,917	9,939	36,856
2026 Total Depreciation	324,375	139,208	463,583	(210,386)	(72,487)	(282,873)	113,989	66,721	180,710
2026 Closing Gross Assets	3,726,335	1,582,415	5,308,750	-	-	-	3,726,335	1,582,415	5,308,750
2026 Closing Accum Deprn	2,413,349	1,016,638	3,429,987	810,614	279,281	1,089,895	3,223,963	1,295,919	4,519,882
2026 Closing Net Book Value	1,312,986	565,777	1,878,763	(810,614)	(279,281)	(1,089,895)	502,372	286,496	788,868

Table 1.2B – Rate Base

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Average Gross Fixed Assets	\$378,590,894	\$378,111,298	(\$479,596)	\$374,486,297	(\$3,625,000)
Average Accumulated Depreciation	\$209,633,086	\$209,666,481	\$33,395	\$210,813,464	\$1,146,983
Average Net Book Value	\$168,957,808	\$168,444,817	(\$512,992)	\$163,672,833	(\$4,771,983)
Working Capital Base	\$208,567,641	\$207,419,166	(\$1,148,475)	\$207,013,436	(\$405,730)
Working Capital Allowance (%)	7.50%	7.50%	0.00%	7.50%	0.00%
Working Capital Allowance (\$)	\$15,642,573	\$15,556,437	(\$86,136)	\$15,526,008	(\$30,430)
Rate Base	\$184,600,382	\$184,001,254	(\$599,127)	\$179,198,840	(\$4,802,413)

Evidence:

Application:

Exhibit 1 Sections 1.2.4 C

Exhibit 2, inclusive of Appendix A (DSP)

IRs:

2-Staff-3, 2-Staff-6, 2-Staff-7, 2-Staff-11, 2-Staff-15, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, 2-Intervenor-18, 2-Intervenor-19, 2-Intervenor-20, 2-Intervenor-21, 2-Intervenor-44, 2-Intervenor-50, 2-Intervenor-65, , 2-Intervenor-73

Clarifying Question Responses:

Staff-99, Staff-100, Staff-101, SC-CCC-1, SC-CCC-2

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

1.3 Is the addition of previously approved Incremental Capital Module project assets to rate base appropriate?

The Parties agree with the addition of previously approved Incremental Capital Module assets to BHI's rate base, subject to the disallowance of \$160,692 (approximately 3%)

from the OEB's Decision and Order¹, which is included in the \$2M reduction to opening rate base noted above in issue 1.2(a).

Evidence:

Application:

Exhibit 2, Section 2.8

IRs:

2-Staff-19, 2-Intervenor-28, 2-Intervenor-52

Clarifying Question Responses:

Staff-98, SEC-CQ-4

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

¹ EB-2024-0010, Decision and Order, December 17, 2024, p.27

2. OM&A

2.1 Are the proposed OM&A expenditures appropriate?

Complete Settlement:

For the purposes of settlement, the Parties agree to reduce BHI's 2026 Test Year OM&A envelope before Property Taxes by \$4.20M from \$30,157,314 to \$25,957,314.

Table 2.1A identifies the changes in OM&A expenses as compared to that which was filed in BHI's original Application.

The settled reductions to each individual OM&A category are being provided by the Applicant for illustrative purposes. The Parties agree that the revised OM&A expenditures are reasonable to deliver customer services and upkeep the distribution system in accordance with good utility practice.

Table 2.1A – Summary of OM&A Expenses -Variance

Description	2021 Actuals	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Operations	\$4,928,079	\$5,859,812	\$5,906,327	\$46,515	\$5,081,338	(\$824,989)
Maintenance	\$5,763,352	\$8,043,725	\$8,043,725	\$0	\$6,741,706	(\$1,302,019)
Sub-Total	\$10,691,431	\$13,903,537	\$13,950,052	\$46,515	\$11,823,044	(\$2,127,008)
Billing and Collecting	\$2,683,766	\$3,363,904	\$3,363,904	\$0	\$2,911,162	(\$452,742)
Community Relations	\$14,800	\$31,300	\$31,300	\$0	\$21,300	(\$10,000)
Administration and General	\$7,737,404	\$12,741,360	\$12,812,058	\$70,698	\$11,201,808	(\$1,610,250)
Sub-Total	\$10,435,970	\$16,136,564	\$16,207,262	\$70,698	\$14,134,270	(\$2,072,992)
Total 2-JA	\$21,127,400	\$30,040,101	\$30,157,314	\$117,213	\$25,957,314	(\$4,200,000)

Evidence:

Application:

Exhibit 1, Sections 1.2.4 D and 1.6

Exhibit 4

IRs:

4-Staff-38, 4-Staff-39, 4-Staff-40, 4-Staff-42, 4-Staff-43, 4-Staff-44, 4-Staff-45, 4-Staff-46, 4-Staff-47, 4-Staff-48, 4-Staff-49, 4-Staff-50, 4-Staff-51, 4-Staff-52, 4-Staff-53, 4-Staff-54, 4-Staff-56, 4-Staff-57, 4-Staff-58, 4-Staff-59, 4-Staff-60, 4-Staff-61, 4-Staff-62, 4-Staff-63, 4-Staff-64, 4-Staff-65, 4-Staff-66, 4-Staff-67, 1-Intervenor-2, 1-Intervenor-3, 1-Intervenor-5, 1-Intervenor-6, 1-Intervenor-7, 1-Intervenor-8, 1-Intervenor-9, 1-Intervenor-11, 4-Intervenor-92, 4-Intervenor-93, 4-Intervenor-94, 4-Intervenor-95, 4-Intervenor-96, 4-Intervenor-97, 4-Intervenor-98, 4-Intervenor-99, 4-Intervenor-100, 4-Intervenor-101, 4-Intervenor-102, 4-Intervenor-103, 4-Intervenor-104, 4-Intervenor-105, 4-Intervenor-106, 4-Intervenor-107, 4-Intervenor-108, 4-Intervenor-109, 4-Intervenor-110, 4-Intervenor-111, 4-

Intervenor-112, 4-Intervenor-113, 4-Intervenor-114, 4-Intervenor-115, 4-Intervenor-116, 4-Intervenor-117, 4-Intervenor-118, 4-Intervenor-119, 4-Intervenor-120, 4-Intervenor-123, 4-Intervenor-124, 4-Intervenor-125

Clarifying Question Responses:

Staff-106, Staff-107, Staff-108, Staff-109, Staff-110, Staff-111, Staff-112, Staff-113, SC-CCC-5, SC-CCC-6, SC-CCC-8

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

2.2 Is the proposed shared services cost allocation methodology and the quantum appropriate?

Complete Settlement:

The Parties agree with BHI's proposed shared services cost allocation methodology and the quantum.

Evidence:

Application:

Exhibit 4, Section 4.3.2

IRs:

4-Intervenor-121, 4-Intervenor-122

Clarifying Question Responses:

SC-CCC-9

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

3. Cost of Capital, PILs, and Revenue Requirement

3.1 Is the proposed cost of capital (interest on debt, return on equity) and capital structure appropriate?

Complete Settlement:

The Parties agree to use the proposed capital structure, and agree to update the return on equity, and short-term debt rates to incorporate those issued by the OEB as part of the 2026 Cost of Capital parameters which will be published in the fourth quarter of 2025.

The Parties agree that BHI will adjust the long-term debt rate on its 2026 debt issuance from 4.60% to the deemed long-term debt rate set by the OEB as part of the 2026 Cost of Capital parameters which will be published in the fourth quarter of 2025. The Parties further agree that BHI will not issue new long-term debt in 2025.

Evidence:

Application:

Exhibit 1 Section 1.2.4 E

Exhibit 5

IRs:

5-Staff-68, 5-Staff-69, 5-Staff-70, 5-Staff-71, 1-Intervenor-12, 5-Intervenor-126

Clarifying Question Responses:

SEC-CQ-5

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

3.2 Is the proposed PILs (or Tax) amount appropriate?

Complete Settlement:

The Parties accept the appropriateness of the Payments-in-Lieu of Taxes (PILs) and other tax-related components of BHI's revenue requirement as adjusted in the PILS Workform to reflect the changes set forth in this Settlement Proposal.

The Parties accept BHI's proposal that the accelerated CCA rules introduced by Bill C-97 were applied in the PILs tax models, and that the maximum accelerated CCA was claimed for 2026. Account 1592, PILs and Tax Variances, Sub-account CCA Changes, will continue to track the impact of further changes to the CCA rules over the IRM period.

The Parties agree to use the unsmoothed approach to account for the difference in revenue requirement as result of the phasing out period of the Accelerated Investment Incentive ("AII"). Specifically, the Parties agree that BHI will not increase PILs expense in the 2026 Test Year to smooth the impact of the phasing out period of the AII in 2028-2030; and BHI will use the Account 1592 sub-account CCA Changes to track the full revenue requirement impacts of the phasing out period of the AII over the IRM period. The balance in this sub-account is to be disposed of at BHI's next rebasing application.

Evidence:

Application:

Exhibit 1 Sections 1.2.4 A, 1.8.6

Exhibit 6

IRs:

6-Staff-73, 6-Staff-74, 6-Staff-75, 6-Staff-76, 6-Staff-77, 6-Staff-78

Clarifying Question Responses:

Staff-114, Staff-115

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2026_PILS_Workform_BHI

Supporting Parties: All

Parties Taking No Position: None

3.3 Is the proposed Other Revenue forecast appropriate?

Complete Settlement:

For the purposes of settlement, the Parties agree to increase Other Revenue by \$150,000 as compared to that which was filed in BHI's interrogatory responses, and as identified in Table 3.5H of this Settlement Proposal.

Evidence:

Application:

Exhibit 1 Sections 1.2.4 A

Exhibit 6, Section 6.3

IRs:

6-Staff-72, 6-Intervenor-127, 6-Intervenor-128, 6-Intervenor-129

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

3.4 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

Complete Settlement:

The Parties agree that the impacts of any proposed changes in accounting standards, policies, estimates, and adjustments have been properly identified and recorded, and that the rate treatment of these impacts is appropriate. The Parties accept BHI's proposal to change the depreciation rate for USoA 1611 from 20% (5 years) to 10-20% (5-10 years) to reflect a change

to the depreciation rate for BHI's CIS and GIS software from 5 years, as approved in BHI's last rebasing application², to 10 years.

Evidence:

Application:

Exhibit 1 Sections 1.8.9

Exhibit 2, Section 2.4

IRs:

2-Staff-28

Clarifying Question Responses:

Staff-100, CCC-1

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2026_PILS_Workform_BHI

Supporting Parties: All

Parties Taking No Position: None

3.5 Is the proposed calculation of the Revenue Requirement appropriate?

Complete Settlement:

Subject to the modifications set out herein, the Parties agree with the proposed calculation of revenue requirement. The elements of Revenue Requirement are identified in Tables 3.5A to 3.5H below.

² EB-2020-0007

Table 3.5A – Revenue Requirement

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Revenue Requirement					
OM&A (Excluding Property Taxes and LEAP)	\$29,975,101	\$30,092,314	\$117,213	\$25,892,314	(\$4,200,000)
Property Taxes	\$375,892	\$375,892	\$0	\$375,892	\$0
LEAP	\$65,000	\$65,000	\$0	\$65,000	\$0
Depreciation and Amortization	\$10,046,886	\$10,065,714	\$18,828	\$9,652,371	(\$413,342)
Total	\$40,462,879	\$40,598,920	\$136,041	\$35,985,577	(\$4,613,342)
Regulated Return on Capital	\$11,445,947	\$11,401,653	(\$44,294)	\$11,091,448	(\$310,205)
Income Taxes Grossed Up	\$931,830	\$925,602	(\$6,228)	\$873,601	(\$52,001)
Service Revenue Requirement	\$52,840,656	\$52,926,174	\$85,518	\$47,950,627	(\$4,975,547)
Other Revenues	\$4,355,525	\$4,339,019	(\$16,506)	\$4,489,019	\$150,000
Base Revenue Requirement	\$48,485,131	\$48,587,155	\$102,025	\$43,461,608	(\$5,125,547)
Distribution Revenue at Current Rates	\$38,414,728	\$38,349,171	(\$65,557)	\$38,789,248	\$440,077
Grossed Up Revenue Deficiency	\$10,070,403	\$10,237,984	\$167,581	\$4,672,360	(\$5,565,624)

Table 3.5B – Rate Base

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Average Gross Fixed Assets	\$378,590,894	\$378,111,298	(\$479,596)	\$374,486,297	(\$3,625,000)
Average Accumulated Depreciation	\$209,633,086	\$209,666,481	\$33,395	\$210,813,464	\$1,146,983
Average Net Book Value	\$168,957,808	\$168,444,817	(\$512,992)	\$163,672,833	(\$4,771,983)
Working Capital Base	\$208,567,641	\$207,419,166	(\$1,148,475)	\$207,013,436	(\$405,730)
Working Capital Allowance (%)	7.50%	7.50%	0.00%	7.50%	0.00%
Working Capital Allowance (\$)	\$15,642,573	\$15,556,437	(\$86,136)	\$15,526,008	(\$30,430)
Rate Base	\$184,600,382	\$184,001,254	(\$599,127)	\$179,198,840	(\$4,802,413)

Table 3.5C – Cost of Power

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Power Purchased	\$107,290,082	\$105,708,104	(\$1,581,978)	\$107,612,192	\$1,904,088
Global Adjustment	\$42,297,885	\$42,343,899	\$46,014	\$43,545,753	\$1,201,853
Wholesale Market Service Charge	\$9,211,026	\$9,118,656	(\$92,370)	\$9,311,271	\$192,615
Transmission - Network	\$18,693,132	\$18,914,965	\$221,833	\$19,314,836	\$399,871
Transmission - Connection	\$14,106,259	\$14,005,337	(\$100,922)	\$14,299,543	\$294,206
Smart Meter Entity Charge	\$347,296	\$346,933	(\$363)	\$348,193	\$1,260
Ontario Electricity Rebate	(\$13,794,033)	(\$13,551,935)	\$242,098	(\$13,751,558)	(\$199,624)
Total	\$178,151,648	\$176,885,960	(\$1,265,688)	\$180,680,230	\$3,794,270

Table 3.5D – Working Capital Allowance

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Total Distribution Expenses	\$30,415,993	\$30,533,206	\$117,213	\$26,333,206	(\$4,200,000)
Power Supply Expenses	\$178,151,648	\$176,885,960	(\$1,265,688)	\$180,680,230	\$3,794,270
Total Expenses for Working Capital	\$208,567,641	\$207,419,166	(\$1,148,475)	\$207,013,436	(\$405,730)
Working Capital Allowance %	7.50%	7.50%	0.00%	7.50%	0.00%
Total Working Capital Allowance	\$15,642,573	\$15,556,437	(\$86,136)	\$15,526,008	(\$30,430)

Table 3.5E – Capital Structure and Cost of Capital³

Description	Capitalization Ratios		Rate	Return
	%	\$	%	\$
Debt				
Long-term Debt	56.0%	\$100,351,351	4.34%	\$4,360,023
Short-term Debt	4.0%	\$7,167,954	3.91%	\$280,267
Total Debt	60.0%	\$107,519,304	4.32%	\$4,640,290
Equity				
Common Equity	40.0%	\$71,679,536	9.00%	\$6,451,158
Preferred Shares	0.0%	\$0	0.00%	\$0
Total Equity	40.0%	\$71,679,536	9.00%	\$6,451,158
Total	100.0%	\$179,198,840	6.19%	\$11,091,448

Table 3.5F – Depreciation Expense

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Depreciation Expense	\$10,046,886	\$10,065,714	\$18,828	\$9,652,371	(\$413,342)

Table 3.5G – PILs

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Taxes/PILs (Grossed up)	\$931,830	\$925,602	(\$6,228)	\$873,601	(\$52,001)

Table 3.5H – Other Revenue

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Specific Service Charges	(\$270,029)	(\$283,109)	(\$13,080)	(\$283,109)	\$0
Late Payment Charges	(\$270,000)	(\$270,000)	\$0	(\$270,000)	\$0
Other Operating Revenues	(\$2,884,844)	(\$2,855,258)	\$29,586	(\$2,839,922)	\$15,336
Other Income or Deductions	(\$930,651)	(\$930,651)	\$0	(\$1,095,987)	(\$165,336)
Total	(\$4,355,525)	(\$4,339,019)	\$16,506	(\$4,489,019)	(\$150,000)

Evidence:

Application:

Exhibit 1 Sections 1.2.4 A

Exhibit 6

IRs:

None

³ Short-term debt rate, long-term debt rate and return-on-equity to be adjusted to reflect OEB 2026 Cost of Capital parameters to be published fourth quarter of 2025

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2025_RRWF_BHI

Supporting Parties: All

Parties Taking No Position: None

4 Load Forecast

4.1 Is the proposed load forecast methodologies and the resulting load forecasts appropriate?

Complete Settlement:

The Parties agree to the proposed load forecast that was filed as part of VECC-CQ-12, which includes the COVID-19 variable for the 2026 load forecast for Residential, GS<50 and GS>50 customers, subject to the following adjustments:

- CDM Adjustments*: In respect of each rate class, the 2025 load forecast will not include CDM amounts related to the Local Initiatives program, and, the CDM amounts related to the Local Initiatives program proposed for the 2026 load forecast will be reduced by 50%.⁴
- Lost GS>50kW customer*: Update the Lost Loads due to the lost customer by 13,081 kW rather than 14,023 kW, to account for the lost GS>50 kW customer that ceased operations in early 2025.⁵
- Residential Customer Count*: For the purpose of settlement, the forecasted quantity of residential customers in 2026 will be increased by 250 customers, from 63,050 to 63,300.⁶

The resulting load forecast, customer counts and CDM adjustments are identified below in Tables 4.1A to 4.1C.

Table 4.1A – Load Forecast

Rate Class	Application		Interrogatories		Settlement	
	kWh	kW	kWh	kW	kWh	kW
Residential	554,448,693		547,590,732		550,433,963	
GS<50 kW	168,539,128		165,906,773		173,076,730	
GS>50 kW	732,505,202	1,968,903	732,355,269	1,974,932	753,189,947	2,031,031
Streetlighting	5,608,031	15,672	5,609,578	15,677	5,609,578	15,677
Unmetered Scattered Load	3,312,078		3,307,852		3,307,852	
Total	1,464,413,133	1,984,575	1,454,770,203	1,990,609	1,485,618,070	2,046,708

Table 4.1B – Customer Forecast (Annual Average)

Rate Class	Determinant	Application	Interrogatories	Settlement
Residential	Customers	63,119	63,050	63,300
GS<50 kW	Customers	5,823	5,786	5,786
GS>50 kW	Customers	952	956	956
Streetlighting	Connections	17,348	17,353	17,353
Unmetered Scattered Load	Connections	584	584	584

⁴ 3-Staff-37.

⁵ VECC-CQ-6 ; 3-Intervenor-86(c) ; application, Exhibit 3, p.51.

⁶ VECC-CQ-11(a).

Table 4.1C – CDM Adjustment

Rate Class	Application		Interrogatories		Settlement	
	kWh	kW	kWh	kW	kWh	kW
GS<50 kW	4,009,240		3,614,601		2,202,893	
GS>50 kW	18,053,728	48,527	16,267,834	43,869	11,170,079	30,121
Total	22,062,969	48,527	19,882,435	43,869	13,372,972	30,121

Evidence:

Application:

Exhibit 1 Section 1.2.4 B

Exhibit 3

IRs:

3-Staff-31, 3-Staff-32, 3-Staff-33, 3-Staff-34, 3-Staff-35, 3-Staff-36, 3-Staff-37, 4-Staff-41, 1-Intervenor-9, 2-Intervenor-29, 3-Intervenor-81, 3-Intervenor-82, 3-Intervenor-83, 3-Intervenor-84, 3-Intervenor-85, 3-Intervenor-86, 3-Intervenor-87, 3-Intervenor-88, 3-Intervenor-89, 3-Intervenor-90, 3-Intervenor-91

Clarifying Question Responses:

Staff-105, VECC-CQ-1, VECC-CQ-2, VECC-CQ-3, VECC-CQ-4, VECC-CQ-5, VECC-CQ-6, , VECC-CQ-10, VECC-CQ-12

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_Load_Forecast_Model_BHI

Supporting Parties: All

Parties Taking No Position: None

5 Cost Allocation, Rate Design, and Other Charges

5.1 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

Complete Settlement:

The Parties agree with the cost allocation methodology and allocations as filed in this Settlement Proposal.

The Parties agree to adjust the revenue-to-cost ratios of the GS<50 kW, Streetlighting and Unmetered Scattered Load rate classes to the upper end of the Board's Policy range (i.e., to 120%). The Parties agree to allocate 100% of the associated revenue shortfall to the GS>50 kW rate class as the resulting revenue to cost ratio does not exceed either 100% or the revenue to cost ratio of any of the remaining classes. The Parties agree to the revenue-to-cost ratios identified in Table 5.1A below.

Table 5.1A – Proposed Revenue to Cost Ratios

Rate Class	R:C Ratios from Cost Allocation Model - Line 75 Sheet O1	Proposed R:C Ratio	Board Target Low	Board Target High
Residential	98.75%	98.75%	85%	115%
GS<50 kW	124.00%	120.00%	80%	120%
GS>50 kW	91.41%	93.51%	80%	120%
Streetlighting	124.29%	120.00%	80%	120%
USL	133.39%	120.00%	80%	120%

Evidence:

Application:

Exhibit 1 Section 1.2.4 F

Exhibit 7

Exhibit 8

IRs:

7-Staff-80, 7-Intervenor-130, 7-Intervenor-131, 7-Intervenor-132, 7-Intervenor-133, 7-Intervenor-134, 8-Intervenor-135, 8-Intervenor-139, 8-Intervenor-146, 8-Intervenor-147

Clarifying Question Responses:

ED-CQ-8, ED-CQ-8, ED-CQ-9, ED-CQ-10, ED-CQ-11, ED-CQ-12, ED-CQ-13, ED-CQ-14, VECC-CQ-7, VECC-CQ-8, VECC-CQ-9

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2026_Cost_Allocation_Model_v1.0_BHI

Supporting Parties: All

Parties Taking No Position: None

5.2 Is the proposed rate design, including fixed/variable splits, appropriate?

Complete Settlement:

The Parties agree that BHI's rate design proposed in its Application, including the proposed fixed/variable splits, are appropriate.

Table 5.2A below identifies the proposed distribution revenue charges.

Table 5.2A – Proposed Fixed/Variable Distribution Charges

Rate Class	Unit	2025 Distribution Rates Application	2026 Distribution Rates Application	2026 Distribution Rates Interrogatories	Variance	2026 Distribution Rates Settlement	Variance	Fixed / Variable Split
			a	b	c = b-a	d	e = d-b	
Residential								
Monthly Service Charge	\$	32.64	41.19	41.35	0.16	36.57	- 4.78	100.0%
Volumetric Charge	\$/kWh	-	-	-	-	-	-	0.0%
GS<50 kW								
Monthly Service Charge	\$	29.29	36.96	37.11	0.15	28.76	- 8.35	34.3%
Volumetric Charge	\$/kWh	0.0193	0.0244	0.0245	0.0001	0.0221	- 0.0024	65.7%
GS>50 kW								
Monthly Service Charge	\$	78.66	84.65	84.76	0.11	73.13	- 11.63	8.8%
Volumetric Charge	\$/kW	3.8537	4.9155	4.9212	0.0057	4.4916	- 0.4296	91.2%
Streetlighting								
Monthly Service Charge	\$	0.65	0.78	0.81	0.03	0.70	- 0.11	65.0%
Volumetric Charge	\$/kW	4.6705	5.5695	5.8023	0.2328	5.0359	- 0.7664	35.0%
USL								
Monthly Service Charge	\$	10.81	10.76	12.15	1.39	10.81	- 1.34	54.9%
Volumetric Charge	\$/kWh	0.0188	0.0187	0.0212	0.0025	0.0188	- 0.0024	45.1%

Evidence:

Application:

Exhibit 1, Section 1.2.4 F

Exhibit 8, Section 8.1

IRs:

8-Intervenor-137

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2026_RRWF_BHI

Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Supporting Parties: All

Parties Taking No Position: None

5.3 Are the proposed Retail Transmission Service Rates appropriate?

Complete Settlement:

The Parties agree that the proposed Retail Transmission Service Rates are appropriate as identified in Table 5.3A below. BHI has updated the UTR and Hydro One sub transmission rates for 2025 in accordance with the OEB's rate orders EB-2024-0244 and EB-2024-0032 respectively⁷. The updated RTSR model includes the new EV Charging (EVC) rate for electric vehicle (EV) charging stations.

⁷ 8-Staff-81

Table 5.3A – Retail Transmission Service Rates

Proposed 2026 RTSR Network Service Rate						
Rate Class	Unit	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Residential	kWh	0.0122	0.0124	0.0002	0.0124	-
GS<50 kW	kWh	0.0117	0.0119	0.0002	0.0119	-
GS>50 kW	kW	4.8092	4.9016	0.0923	4.9016	-
Streetlighting	kW	3.5146	3.5821	0.0675	3.5821	-
USL	kWh	0.0117	0.0119	0.0002	0.0119	-

Proposed 2026 RTSR Line and Transformation Connection Service Rate						
Rate Class	Unit	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Residential	kWh	0.0092	0.0092	-	0.0092	-
GS<50 kW	kWh	0.0084	0.0084	-	0.0084	-
GS>50 kW	kW	3.6523	3.6523	-	3.6523	-
Streetlighting	kW	0.0084	0.0084	-	0.0084	-
USL	kWh	2.5991	2.5991	-	2.5991	-

Evidence:

Application:

Exhibit 1 Sections 1.2.4 F

Exhibit 8, Section 8.2

IRs:

8-Staff-81, 8-Intervenor-138

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_2026_RTSR_Workform_BHI

Supporting Parties: All

Parties Taking No Position: None

5.4 Are the proposed loss factors appropriate, considering OEB requirements and utility measures to cost-effectively reduce distribution losses?

Complete Settlement:

The Parties agree that the proposed loss factors filed in BHI's interrogatory responses are appropriate, considering OEB requirements and utility measures to cost-effectively reduce distribution losses.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including items 5 and 6.

Table 5.4A – OEB Appendix 2-R

	Description	Historical Years					5-Year Average
		2020	2021	2022	2023	2024	
	Losses Within Distributor's System						
A	"Wholesale" kWh delivered to distributor (higher value)	1,560,832,200	1,570,411,100	1,582,272,268	1,538,474,828	1,566,109,307	1,563,619,941
B	"Wholesale" kWh delivered to distributor (lower value)	1,555,579,189	1,563,660,424	1,577,204,650	1,533,707,118	1,561,257,762	1,558,281,829
C	microFIT kWh supplied to distributor	9,882,707	9,718,702	9,647,170	8,663,953	9,039,538	9,390,414
D	Other Embedded Generation	-	-	-	-	-	-
E	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Wholesale" kWh delivered to distributor = B + C + D - E	1,565,461,896	1,573,379,126	1,586,851,820	1,542,371,071	1,570,297,300	1,567,672,243
G	"Retail" kWh delivered by distributor	1,504,792,712	1,513,843,506	1,531,698,249	1,484,415,329	1,511,587,889	1,509,267,537
H	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
I	Net "Retail" kWh delivered by distributor = G - H	1,504,792,712	1,513,843,506	1,531,698,249	1,484,415,329	1,511,587,889	1,509,267,537
J	Loss Factor in Distributor's system = F / I	1.0403	1.0393	1.0360	1.0390	1.0388	1.0387
	Losses Upstream of Distributor's System						
K	Supply Facilities Loss Factor	1.0034	1.0043	1.0032	1.0031	1.0031	1.0034
	Total Losses						
L	Total Loss Factor = J x K	1.0438	1.0438	1.0393	1.0423	1.0420	1.0422

Table 5.4B – Total Loss Factors

Customer	Distribution Loss Factor	SFLF	Total Loss Factor
Secondary Metered Customer <5,000kW	1.0387	1.0034	1.0422
Primary Metered Customer <5,000kW	1.0284	1.0034	1.0319

Evidence:

Application:

Exhibit 1 Sections 1.2.4 F

Exhibit 8, Section 8.8

IRs:

2-Staff-26, 8-Intervenor-136, 8-Intervenor-140, 8-Intervenor-141, 8-Intervenor-142, 8-Intervenor-143, 8-Intervenor-144, 8-Intervenor-145

Clarifying Question Responses:

ED-CQ-15, ED-CQ-16, ED-CQ-17

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_OEB_Chapter2Appendices_BHI

Supporting Parties: All

Parties Taking No Position: None

5.5 Are the Specific Service Charges and Retail Service Charge appropriate?

Complete Settlement:

The Parties agree that BHI's proposed Specific Service Charges, Retail Service Charges, and Pole Attachment Charges as identified in Appendix B – Proposed Tariff of Rates and Charges, are appropriate.

Appendix A, which forms a binding and integral part of this Settlement Proposal, contains commitments that are integral to this issue, including item no. 7.

Evidence:

Application:

Exhibit 1 Sections 1.2.4 F

Exhibit 8, Sections 8.3, 8.4, 8.5, 8.6, 8.7

IRs:

6-Intervenor-127, 6-Intervenor-128, 6-Intervenor-129

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Supporting Parties: All

Parties Taking No Position: None

5.6 Are rate mitigation proposals required and appropriate?

Complete Settlement:

The Parties agree to dispose of the deferral and variance accounts over a two-year period for rate mitigation purposes.

Evidence:

Application:

Exhibit 1 Sections 1.2.4 F, 1.2.4 H

Exhibit 8, Sections 8.11, 8.12

IRs:

None

Clarification Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

6 Deferral and Variance Accounts

6.1 Are BHI's proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, appropriate?

Complete Settlement:

Subject to the modification set out herein, the Parties agree that the proposals for deferral and variance accounts, including the balances in the existing accounts and their disposition, requests for discontinuation of accounts, and the continuation of existing accounts, as filed in this Settlement Proposal are appropriate. The balances proposed for disposition are identified in Table 6.1C below and are attached as Settlement_Attachment_DVA_Continuity_Schedule_BHI. Specifically, for the purposes of settlement:

- a) *Group 1 Deferral and Variance Accounts ("DVAs")*: The Parties agree that the proposed balances in the existing accounts and their disposition as filed in the Application on April 16, 2025 are appropriate and agree that BHI dispose of its Group 1 DVAs on an interim basis as at December 31, 2024, including interest to December 31, 2025. BHI has updated the carrying charges based on the OEB prescribed interest rate for Q3 2025, as reflected in the updated DVA Continuity Schedule filed with this Settlement Proposal.
- b) *Group 2 DVAs – Account 1509 Impacts Arising from the COVID-19 Emergency*: For the purposes of settlement, the Parties agree to record a balance of \$115,987 for disposition in Account 1509 – Impacts Arising from the COVID-19 Emergency, rather than \$320,439 as provided in the Application. This reflects no recovery of the 2021 incremental costs, and 50% recovery of the 2020 incremental costs incurred by BHI as a result of the COVID-19 Emergency, as these amounts were recorded in the account for which a 50% recovery rate applies.

Group 2 DVAs – Account 1592 PILS & Tax Variance – CCA Changes: As discussed in Issue 3.2, the Parties agree to continue Sub-Account of 1592 - PILs and Tax Variances - CCA Changes to capture the revenue requirement impact of the accelerated CCA deductions for eligible property.

For the purposes of settlement, the Parties agree to record the balance of \$411,547 in Account 1592, CCA sub-account as identified in Table 6.1A below, which represents the revenue requirement impact of the phase-out of accelerated CCA deductions for eligible property in 2024 and 2025. Principal balances are updated for the capital expenditure and in-service additions changes identified in Issue 1.1 above, and carrying charges are updated to incorporate the OEB's prescribed interest rate for Q3 2025. The methodology BHI used to calculate the amount in question was based on actual additions for 2024 and 2025, not

the 2024 and 2025 additions approved in BHI's last rebasing application⁸. For the purpose of settlement, the Parties accept the amount but not necessarily the methodology for calculating the amount in question.

Table 6.1A – PILs & Tax Variance – CCA Changes

Description	2024	2025	Total
CCA in Rates	\$10,274,262	\$9,858,152	\$20,132,414
Actual CCA	\$9,564,197	\$9,470,462	\$19,034,659
Difference in CCA	\$710,065	\$387,690	\$1,097,755
Tax Impact @ 26.5%	\$188,167	\$102,738	\$290,905
Grossed up PILs	\$256,010	\$139,779	\$395,789
Add Carrying Charges			\$15,758
Total Requested for Disposition			\$411,547

- c) *Group 2 DVAs – Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”) – Account 1568:* The Parties agree that no further entries to the LRAMVA are permitted at this time, consistent with the OEB's finding in its Decision and Order in BHI's 2024 rate application.⁹ Notwithstanding the foregoing, BHI reserves the right to seek the OEB's approval to request use of the LRAMVA (i) if BHI plans to conduct one or more activities that become eligible to be recorded in the LRAMVA based on future OEB policy developments, including but not limited to policy developments resulting from the ongoing Electricity Demand-Side Management Consultation (EB-2025-0156); and (ii) as part of a future rebasing application.
- d) *Group 2 DVAs – All Other:* The Parties agree that the balances in the following DVAs as originally filed April 16, 2025 and updated to reflect the OEB prescribed Q3 2025 interest rate, as identified in Table 6.1C below, are appropriate:
- Pole Attachment Revenue Variance
 - Customer Choice Initiative Costs
 - Green Button Initiative Costs
 - Capital Additions Dundas Street Road Widening Project
 - Capital Additions Waterdown Rd Road Widening Project
 - Collection Charge Lost Revenue
 - Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges
 - Extraordinary Event Costs (Z Factor) – 2022 Wind Storm

⁸ EB-2020-0007

⁹ EB-2023-0008, Decision and Rate Order, December 14, 2023, p11

- e) *Disposition Period*: The Parties agree to a disposition period of 2 years for all Group 1 and Group 2 DVAs.
- f) *Continuation/Discontinuation of DVAs*: The Parties agree to continue/discontinue Group 2 DVAs as identified in Table 6.1B below:

Table 6.1B – Status of Group 2 DVAs

Variance Account	USoA	Continue/ Discontinue
Group 2		
Pole Attachment Revenue Variance	1508	Discontinue
Customer Choice Initiative Costs	1508	Discontinue
Local Initiatives Program Costs	1508	Discontinue
Green Button Initiative Costs	1508	Discontinue
Designated Broadband Project Impacts	1508	Discontinue
ULO Implementation Cost	1508	Discontinue
GOCA Variance Account	1508	Discontinue
LEAP EFA Funding Deferral Account	1508	Discontinue
Capital Additions Dundas Street Road Widening Project	1508	Discontinue
Capital Additions Waterdown Rd Road Widening Project	1508	Discontinue
Collection Charge Lost Revenue	1508	Discontinue
ICM - 2025 Dundas Street Road Widening Project	1508	Continue
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	Continue
Extra-Ordinary Event Costs - 2022 Wind Storm (Z-Factor)	1572	Discontinue
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	Continue
Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	1568	Continue
Impacts Arising from the COVID-19 Emergency	1509	Discontinue
Incremental Cloud Computing Implementation Costs	1511	Discontinue

- g) *New DVAs* – The Parties agree to establish the following Group 2 DVAs:
- *System Access Variance Account* – As described in Issue 1.1 and Appendix C.
 - *Cloud Computing Implementation Costs - ERP Replacement* – The Parties agree to establish a new deferral account to record cloud computing implementation and ongoing subscription costs in respect of BHI’s Enterprise Resource Planning system (“ERP”) replacement. Any amounts recorded in the account must be offset by the revenue requirement of the on-premise ERP replacement capital expenditures avoided during the IRM period through the implementation of a cloud-based ERP solution. For clarity, the avoided ERP replacement capital expenditures shall be no greater than \$2,143,000, but may be lower if some amounts related to this project are capitalized in accordance with IFRS. The generic Incremental Cloud Computing Implementation Costs Account (Account 1511) will be closed in accordance with the Board’s “Cost of Capital and Other Matters” Decision on March 27, 2025¹⁰.

¹⁰ EB-2024-0063, Section 3.8, p103

Table 6.1C – Deferral and Variance Account Balances

Variance Account	Incorporate Principal Activity to:	USoA	Application a	Interrogatories b	Variance c = b-a	Settlement d	Variance e = d-b
Group 1							
Smart Metering Entity Charge Variance Account	31-Dec-24	1551	(\$55,993)	(\$55,993)	\$0	(\$55,926)	\$67
RSVA - Wholesale Market Service Charge	31-Dec-24	1580	(\$423,745)	(\$423,745)	\$0	(\$423,234)	\$511
Variance WMS – Sub-account CBR Class A	31-Dec-24	1580	\$0	\$0	\$0	\$0	\$0
Variance WMS – Sub-account CBR Class B	31-Dec-24	1580	\$661,564	\$661,564	\$0	\$660,760	(\$804)
RSVA - Retail Transmission Network Charge	31-Dec-24	1584	\$301,641	\$301,641	\$0	\$301,266	(\$374)
RSVA - Retail Transmission Connection Charge	31-Dec-24	1586	(\$274,469)	(\$274,469)	\$0	(\$274,140)	\$329
RSVA - Power (excluding Global Adjustment)	31-Dec-24	1588	\$722,864	\$722,864	\$0	\$721,999	(\$865)
RSVA - Global Adjustment	31-Dec-24	1589	\$3,026,767	\$3,026,767	\$0	\$3,023,132	(\$3,635)
Total Group 1 Balances			\$3,958,628	\$3,958,628	\$0	\$3,953,857	(\$4,771)
Group 2							
Pole Attachment Revenue Variance	31-Dec-25	1508	\$283,642	\$283,642	\$0	\$283,332	(\$310)
Customer Choice Initiative Costs	31-Dec-25	1508	\$158,757	\$158,757	\$0	\$158,589	(\$168)
Green Button Initiative Costs	31-Dec-25	1508	\$260,320	\$260,320	\$0	\$260,108	(\$212)
Capital Additions Dundas Street Road Widening Project	31-Dec-25	1508	(\$15,264)	(\$15,264)	\$0	(\$15,259)	\$5
Capital Additions Waterdown Rd Road Widening Project	31-Dec-25	1508	(\$6,032)	(\$6,032)	\$0	(\$6,026)	\$6
Collection Charge Lost Revenue	30-Apr-21	1508	\$835,348	\$835,348	\$0	\$834,442	(\$906)
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	n/a	1522	(\$77,656)	(\$77,656)	\$0	(\$77,656)	\$0
Extra-Ordinary Event Costs - 2022 Wind Storm (Z-Factor)	31-Dec-24	1572	\$4,749	\$4,749	\$0	\$4,749	\$0
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	31-Dec-25	1592	\$450,322	\$450,322	\$0	\$411,547	(\$38,775)
Impacts Arising from the COVID-19 Emergency	31-Dec-20	1509	\$320,439	\$320,439	\$0	\$115,987	(\$204,452)
Total Group 2 Balances			\$2,214,625	\$2,214,625	\$0	\$1,969,814	(\$244,812)
Total DVA Balances			\$6,173,254	\$6,173,254	\$0	\$5,923,671	(\$249,583)

The updated DVA rate riders are provided in Tables 6.1D to 6.1H below.

Table 6.1D – Group 1 DVA Rate Rider by Rate Class (Excluding Account 1589)

Rate Class	Billing Determinant	kWh/kWs	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/ Variance Accounts
Residential	kWh	550,433,963	69,520	0.0001
GS<50 kW	kWh	173,076,730	33,266	0.0001
GS>50 kW	kW	2,031,031	165,222	0.0407
Unmetered Scattered Load	kWh	3,307,852	726	0.0001
Street Lighting	kW	15,677	1,231	0.0392
Total			\$269,965	

Table 6.1E – Account 1589 Rate Riders by Rate Class

Rate Class	Billing Determinant	kWh/kWs	Allocated GA Balance	Rate Rider for GA
Residential	kWh	3,302,604	19,804	0.0030
GS<50 kW	kWh	17,999,980	107,936	0.0030
GS>50 kW	kWh	464,212,843	2,783,635	0.0030
Unmetered Scattered Load	kWh	-	-	-
Street Lighting	kWh	5,564,701	33,369	0.0030
Total			\$2,944,744	

Table 6.1F – Sub-account 1580 CBR Class B Rate Rider by Rate Class

Rate Class	Billing Determinant	kWh/kWs	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
Residential	kWh	550,433,963	277,872	0.0003
GS<50 kW	kWh	173,076,730	87,373	0.0003
GS>50 kW	kW	1,554,107	276,551	0.0890
Unmetered Scattered Load	kWh	3,307,852	1,670	0.0003
Street Lighting	kW	15,677	2,832	0.0903
Total			\$646,299	

Table 6.1G – Group 2 DVA Rate Riders by Rate Class (excluding 1509)

Rate Class	Billing Determinant	# customers/ kWh/kW	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	# of Customers	63,300	761,073	0.50
GS<50 kW	kWh	173,076,730	220,502	0.0006
GS>50 kW	kW	2,031,031	860,481	0.2118
Unmetered Scattered Load	kWh	3,307,852	4,387	0.0007
Street Lighting	kW	15,677	7,383	0.2355
Total			\$1,853,826	

Table 6.1H – Account 1509 Rate Riders by Rate Class

Rate Class	Billing Determinant	# customers/ kWh/kW	Allocated Account 1509 Balance	Rate Rider for Account 1509
Residential	# of Customers	63,300	73,356	0.05
GS<50 kW	kWh	5,786	15,366	0.11
GS>50 kW	kW	956	26,306	1.15
Unmetered Scattered Load	kWh	584	364	0.03
Street Lighting	kW	17,353	595	0.00
Total			\$115,987	

Evidence:

Application:

Exhibit 1 Sections 1.6 G, 1.10
Exhibit 9

IRs:

9-Staff-82, 9-Staff-83, 9-Staff-84, 9-Staff-85, 9-Staff-86, 9-Staff-87, 9-Staff-88, 9-Staff-89,
9-Staff-90, 9-Staff-91, 9-Staff-92, 9-Staff-93, 9-Staff-94, 9-Staff-95, 9-Intervenor-148, 9-
Intervenor-149, 9-Intervenor-150, 9-Intervenor-151, 9-Intervenor-152, 9-Intervenor-153

Clarifying Question Responses:

Staff-116, Staff-117, Staff-118, Staff-119, Staff-120, SC-CCC-5

Appendices to this Settlement Proposal:

None

Settlement Models:

Settlement_Attachment_DVA_Continuity_Schedule_BHI

Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Supporting Parties: All

Parties Taking No Position: None

7 Other

7.1 Is the proposed effective date appropriate?

Complete Settlement:

The Parties agree that the proposed effective date of January 1, 2026 is appropriate.

Evidence:

Application:

Exhibit 1 Section 1.3.8

IRs:

None

Clarifying Question Responses:

None

Appendices to this Settlement Proposal:

None

Settlement Models:

None

Supporting Parties: All

Parties Taking No Position: None

7.2 Has the applicant responded appropriately to all relevant OEB directions from previous proceedings?

Complete Settlement:

The Parties agree that BHI has responded appropriately to all relevant OEB directions from previous proceedings outlined in the OEB's Decision and Order approving the settlement proposal in EB-2020-0007.¹¹

¹¹ EB-2020-0007, Decision and Order, BHI (April 15, 2021).

Evidence:

Application:

Exhibit 1 Section 1.3.10
DSP, Sections 5.2.3.1.1, 5.2.3.1.4
Exhibit 8, Appendix C
Exhibit 9, Sections 9.1.11, 9.1.12

IRs:

9-Staff-94

Clarifying Question Responses:

Staff-120

Appendices to this Settlement Proposal:

None

Settlement Models:

None

Supporting Parties: All

Parties Taking No Position: None

7.3 Is the proposal for an Advanced Capital Module to replace the existing Supervisory Control and Data Acquisition system and implement a fully integrated Advanced Distribution Management System appropriate?

Complete Settlement:

The Parties agree with BHI's proposal for an ACM to replace BHI's Supervisory Control and Data Acquisition system and procure and implement an Advanced Distribution Management System as provided in the Application and interrogatory responses, provided that BHI will not introduce it as an in-service addition any earlier than January 1, 2028 rather than in 2027 as proposed in the Application and interrogatory responses.

Evidence:

Application:

Exhibit 2 Section 2.7

IRs:

2-Staff-12, 4-Staff-55, 2-Intervenor-23, 2-Intervenor-24, 2-Intervenor-25, 2-Intervenor-26,
2-Intervenor-27

Clarifying Question Responses:

SEC-CQ-1, SEC-CQ-2

Appendices to this Settlement Proposal:

None

Settlement Models:

None

Supporting Parties: All

Parties Taking No Position: None

Appendix A

BHI Settlement Commitments

1. **DSP Metrics:** BHI will continue to track the two new reliability metrics and three new unit cost metrics agreed to as part of the Settlement Proposal in EB-2020-0007 (Page 13).
2. **Reactive and Proactive:** BHI will continue to track proactive versus reactive asset replacement (quantity and total expenditures for both reactive and proactive replacements) for the following asset classes agreed to as part of the Settlement Proposal in EB-2020-0007 (Page 13):
 - a. Pole Replacement
 - b. Underground Rebuilds
 - c. Switchgear Replacement
 - d. Station Transformer Replacement
 - e. MS Feeders Cable Replacement
 - f. Distribution Transformer Replacement
 - g. Switch Replacement
3. **General Commitments:**
 - a. BHI confirms that it is committed to enabling The City of Burlington Climate Action Plan and the Burlington Distribution System Sustainability Plan.
 - b. BHI will undertake all reasonable efforts to collaborate with the IESO, the City of Burlington and other relevant stakeholders to support eDSM program delivery within its service territory. BHI will report on its efforts at the next rebasing.
4. **Energy transition planning:** BHI will consider system demand and capacity to ensure its system can meet future customer and energy transition needs, including DERs. This work will be considered in the development of BHI's next DSP.
5. **Work commitment:** BHI shall carry out the work and activities related to grid modernization, electric vehicles, and cost-effective distribution loss reductions as described in 1-Intervenor-1(b)(items 2-4), 2-Intervenor-36 (f), and 8-Intervenor-140 subject to the following caveats:

- a. That complete execution of the work does not hinder BHI's ability to re-allocate capital to manage to budget envelopes to address unforeseen contingencies;
 - b. The complete execution of the work is contingent on technical feasibility and BHI's ability to procure the necessary equipment;
 - c. Conversion of the existing single-phase circuit (HOWD F3) to the 27.6 kV voltage level is excluded; and
 - d. BHI commits to keeping the power factor above 90% per the DSC.
6. **Distribution losses study continuation (issues: loss factors, operating costs, capital costs):** BHI shall conduct a further study during the next rate period to build on the learnings from its June 21, 2023 report, including:
- a. Update/validate CYME with latest SCADA/AMI (peak and typical), then screen specific feeders and rank by peak line-loss > 4%, and phase imbalance > 10% to produce a prioritized shortlist.
 - b. Evaluate feeders with >10% current imbalance for potential targeted load balancing, with emphasis on cost-effective cases.
 - c. Conduct additional feeder reconfiguration scenarios where the 2023 study showed potential. Run switching/supply-point transfer options with protection/voltage/loading checks and quantify loss reduction and operational impacts.
7. **DER connection charges (issue: rate design, service charges):** BHI shall endeavour to reduce DER connection costs, including but not limited to connection impact assessment costs. This shall include reviewing the practices of Ontario distributors that are leading in efforts to reduce interconnection costs within the next 12 months, including those that can secure lower costs for smaller DER connections and have a graduated fee schedule. BHI shall report on the outcome of this work in its next rates case, including a comparison of its charges with the leading distributors noted above, where available. This work shall be subject to any relevant OEB consultations.

Appendix B

Proposed Tariff of Rates and Charges

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
This schedule supersedes and replaces all previously
approved schedules of Rates, Charges and Loss Factors

EB-2025-0051

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electrical energy to residential customers where such energy is used exclusively in separately metered living accommodation. Customers shall be residing in single dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex, or quadruplex house, with residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	\$	36.57
Rate Rider for Disposition of Account 1509 - effective until December 31, 2027	\$	0.05
Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027	\$	0.50
Smart Metering Entity Charge - effective until December 31, 2027	\$	0.42
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027	\$/kWh	0.0001
Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027	\$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027	\$/kWh	0.0030
Retail Transmission Rate - Network Service Rate	\$/kWh	0.0124
Retail Transmission Rate - Line and Transformation Connection Service Rate	\$/kWh	0.0092

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
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EB-2025-0051

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by BHI to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	\$	28.76
Rate Rider for Disposition of Account 1509 - effective until December 31, 2027	\$	0.11
Smart Metering Entity Charge - effective until December 31, 2027	\$	0.42
Distribution Volumetric Rate	\$/kWh	0.0221
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027	\$/kWh	0.0001
Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027	\$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027	\$/kWh	0.0030
Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027	\$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	\$/kWh	0.0119
Retail Transmission Rate - Line and Transformation Connection Service Rate	\$/kWh	0.0084

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
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EB-2025-0051

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to general service customers with a monthly average peak demand during a calendar year equal to or greater than, or is forecast by Burlington Hydro Inc. to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	\$	73.13
Rate Rider for Disposition of Account 1509 - effective until December 31, 2027	\$	1.15
Distribution Volumetric Rate	\$/kW	4.4916
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027	\$/kW	0.0407
Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027	\$/kW	0.0890
Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027	\$/kWh	0.0030

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2026
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Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027	\$/kW	0.2118
Retail Transmission Rate - Network Service Rate - Interval Metered	\$/kW	4.9016
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	\$/kW	3.6523

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2025-0051

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to low voltage connection assets that operate at 750 volts or less and supply electricity to general service customers whose monthly average peak demand during a calendar year is less than, or forecast by Burlington Hydro Inc. to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	\$	10.81
Rate Rider for Disposition of Account 1509 - effective until December 31, 2027	\$	0.03
Distribution Volumetric Rate	\$/kWh	0.0188
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027	\$/kWh	0.0001
Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027	\$/kWh	0.0003
Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027	\$/kWh	0.0007
Retail Transmission Rate - Network Service Rate	\$/kWh	0.0119
Retail Transmission Rate - Line and Transformation Connection Service Rate	\$/kWh	0.0084

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Burlington Hydro Inc.
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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to roadway lighting customers such as the City of Burlington, the Regional Municipality of Halton, Ministry of Transportation and private roadway lighting, controlled by photo cells. The daily consumption for these customers will be based on the calculated connected load times the required night time or lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	\$	0.70
Rate Rider for Disposition of Account 1509 - effective until December 31, 2027	\$	0.00
Distribution Volumetric Rate	\$/kW	5.0359
Rate Rider for Disposition of Deferral/Variance Accounts - effective until December 31, 2027	\$/kW	0.0392
Rate Rider for Disposition of Capacity Based Recovery (CBR) Account Applicable only for Class B Customers - effective until December 31, 2027	\$/kW	0.0903
Rate Rider for Disposition of Global Adjustment Account - Applicable to Non-RPP Customers Only - effective until December 31, 2027	\$/kWh	0.0030
Rate Rider for Group 2 Deferral/Variance Account Balances - effective until December 31, 2027	\$/kW	0.2355
Retail Transmission Rate - Network Service Rate	\$/kW	3.5821
Retail Transmission Rate - Line Connection Service Rate	\$/kW	2.5991

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	\$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	\$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	\$/kWh	0.0015
Standard Supply Service - Administrative Charge (if applicable)	\$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2025-0051

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	\$	5.00
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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	\$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate	\$	15.00
Credit reference/credit check (plus credit agency costs)	\$	15.00
Statement of account	\$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	\$	30.00

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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Returned cheque (plus bank charges)	\$	15.00
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Non-Payment of Account

Late Payment – per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	\$	65.00
Reconnection at meter - after regular hours	\$	185.00

Other

Temporary service - install & remove - overhead - no transformer	\$	500.00
Specific charge for wireline access to the power poles - \$/pole/year	\$	40.59
(with the exception of wireless attachments)		40.59

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	\$	125.72
Monthly Fixed Charge, per retailer	\$	50.29
Monthly Variable Charge, per customer, per retailer	\$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	\$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	\$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	\$	0.63
Processing fee, per request, applied to the requesting party	\$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	\$	no charge
More than twice a year, per request (plus incremental delivery costs)	\$	5.03

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2025-0051

Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019) \$ 2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0422
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0319

Appendix C

Accounting Orders

Accounting Order #1
Burlington Hydro
Inc. EB-2025-0051

Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account

Effective January 1, 2026, BHI shall establish a new variance account: Account 1508 Sub-account – System Access Variance Account - Revenue Requirement Differential Variance Account (“System Access Variance Account” or “SAVA”). The purpose of this sub-account is to record the revenue requirement associated with the difference between actual 2026 System Access capital additions and the forecasted 2026 System Access capital additions in the Application, net of capital contributions, in the 2026 Test Year and the resulting impact during the IRM period. The baseline net capital additions used to determine any variance will be \$13,500,384. The account will be asymmetrical, such that (i) the maximum amount of additional 2026 System Access net capital additions used to calculate the revenue requirement recorded in the account will be limited to \$2M above the baseline, reflecting BHI’s forecast budget in the application, while (ii) the revenue requirement impact of the aggregate amounts of actual 2026 System Access net capital additions that are less than the baseline will be fully recorded in the account.

If the revenue requirement impact is higher than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the Test Year exceed forecasted System Access net capital additions up to a maximum of \$2M), BHI will make a debit entry in the System Access Variance Account representing a collection from ratepayers. If the revenue requirement impact is lower than forecast in the 2026 Test Year (i.e., the actual System Access net capital additions in the 2026 Test Year are lower than forecasted System Access net capital additions), BHI will make a credit entry in the System Access Variance Account representing a refund to ratepayers. The revenue requirement impact includes depreciation, interest, ROE and PILs. To calculate the PILs expense, the Capital Cost Allowance (“CCA”) under the Accelerated Investment Incentive shall be used, which is consistent with the treatment of the CCA on the net capital additions in the 2026 Test Year. All components of cost of capital will use the weighted average cost of capital, as approved in BHI’s Cost of Service Application EB-2025-0051.

For each rate year from 2027 until BHI’s next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2026 Test Year associated with the difference between actual and budgeted net capital additions in respect of System Access (i.e. the 2026 debit or credit entry described above), escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year as well as growth in billing determinants.

The System Access Variance account shall be disposed of on a final basis as part of any Advanced Capital Module (“ACM”) or Incremental Capital Module (“ICM”) application that BHI may file during the IRM period, or at its next rebasing application. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries should actual System Access in-service net capital additions exceed budgeted System Access in-service net capital additions in the 2026 Test Year.

	<u>Debit</u>	<u>Credit</u>
DR. Account 1508 - Sub-account SAVA – Depreciation	x,xxx.xx	
DR. Account 1508 - Sub-account SAVA – Deemed Interest Expense	x,xxx.xx	
DR. Account 1508 - Sub-account SAVA – Return on Equity	x,xxx.xx	
DR. Account 1508 - Sub-account SAVA – PILs	x,xxx.xx	
CR. Account 4080 - Distribution Services Revenue		x,xxx.xx
DR. Account 1508 - Sub-account SAVA – Carrying Charges	x,xxx.xx	
CR. Account 6035 - Interest Expense		x,xxx.xx

Accounting Order #2
Burlington Hydro
Inc. EB-2025-0051

Account 1508 – Cloud Computing Implementation Costs - ERP Replacement

The Parties agree to establish a new deferral account to record cloud computing implementation and ongoing subscription costs in respect of BHI’s Enterprise Resource Planning system (“ERP”) replacement. Any amounts recorded in the account must be offset by the revenue requirement of the on-premise ERP replacement capital expenditures avoided during the IRM period through the implementation of a cloud-based ERP solution. For clarity, the avoided ERP replacement capital expenditures shall be no greater than \$2,143,000, but may be lower if some amounts related to this project are capitalized in accordance with IFRS. The generic Incremental Cloud Computing Implementation Costs Account (Account 1511) will be closed in accordance with the Board’s “Cost of Capital and Other Matters” Decision on March 27, 2025¹.

The following are sample journal entries to record cloud computing implementation costs in respect of BHI’s ERP replacement:

Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement

Cr. XXXX OM&A Account(s) associated with cloud costs, as applicable

To record cloud computing ERP implementation costs incurred

Dr. 4080 Distribution Revenue

Cr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement

To record the revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital

¹ EB-2024-0063, Section 3.8, p103

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Dr. 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Carrying Charges

Cr. 6035 Other Interest Expense

To record the carrying charges on the net monthly opening balance in Account 1508 - Cloud Computing Implementation Costs – ERP Replacement

The net monthly opening balance of Account 1508 Cloud Computing Implementation Costs – ERP Replacement shall be used to calculate the carrying charges in this account. The net monthly opening balance shall be calculated as:

1. The cumulative cloud computing ERP implementation costs incurred and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement
net of
2. The cumulative revenue requirement impact of the cloud computing ERP implementation costs which otherwise would have been recorded in capital and recorded in Account 1508 Cloud Computing Implementation Costs – ERP Replacement, Sub-account Revenue Requirement

Appendix D

Pre-Settlement Conference Clarification Questions

Staff 96**Primary Station Switchgear**

Ref 1: DSP Appendix A: Material Investment Summary Documents, Material Investment Summary for Switchgear Replacement and Substation Automation

Ref 2: Response to 2-Intervenor-63

Question(s):

- a) At reference 1, Burlington Hydro states that it plans to replace one to two primary station switchgear annually over the DSP period. At reference 2 in Table 1, table 1 shows that it plans to replace four switchgears in 2026 and three each year in the remainder of the term. Please confirm how many switchgears Burlington Hydro Plans to replace each year from 2026-2030.

Response:

- a) BHI plans to replace 4 switchgears in 2026 and 3 each year for the remainder of the rate period.

Staff-97**Capital Contributions****Ref 1: Response to 2-Staff-4**

Question(s):

- a) Please explain how the capital contribution for the Major Transit Station Area Development project was calculated.

Response:

- a) Please refer to BHI's response to clarification question SC-CCC-4.

Staff-98**Previously approved ICM funding****Ref 1: Response to 2-Staff-19****Question(s):**

- a) Please explain the reasons for the revised in-service date for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line section), which has been deferred from 2025 to 2026.
- b) Please summarize the original scope of work planned for completion in 2025 for the Northampton Boulevard to Guelph Line section, and outline any changes to the scope resulting from the revised 2026 in-service date.
- c) Please clarify the factors that led to the change in the project cost for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections) as provided in Chapter 2 Appendices from the prefiled evidence to the response to 1-Staff-01:
 - Northampton Boulevard to Guelph Line: \$4.09M (prefiled evidence) to \$3.79M (response to 1-Staff-01)
 - Guelph Line to Kerns Rd.: \$8.06M (prefiled evidence) to \$9.18M (response to 1-Staff-01)
- d) Please provide a detailed project schedule and cost breakdown for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections), including key milestones, forecasted quarterly expenditures, and the expected in-service date.
- e) Does Burlington Hydro anticipate any further delays to the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections)? If so, please provide details.
- f) Please explain if the project delay will result in credits to customers refunding the ICM funding already collected from customers.

Response:

- a) The revised in-service date for the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line section) is driven by delays from the road authority.
- b) The scope of work for the Northampton Boulevard to Guelph Line section has not changed due to the revised 2026 in-service date and includes the relocation of 43 poles

and associated hardware (i.e. switches, pole mounted transformers, primary and secondary dips, services), 1.8km of overhead high voltage power lines and installation of 300m of underground primary cables for 3 circuits.

c) The factors that led to the change in the project costs are outlined below:

- Northampton Boulevard to Guelph Line: \$4.09M (pre-filed evidence) to \$3.79M (1-Staff-1)

The project cost changed because the Region provided new data that affected the design of the project. The Region had initially designated a 60km per hour speed limit from Northampton Blvd to HWY 407, and changed it to a 80km per hour speed limit, which require BHI's poles to be set further back from the road. This change led to a constraint of space for an overhead line, so a portion of the relocation had to be converted from overhead to underground. This shifted more of the cost responsibility from BHI to the Region.

- Guelph Line to Kerns Rd.: \$8.06M (pre-filed evidence) to \$9.18M (1-Staff-1)

The project cost changed because the Region revised the land profile data from the existing grade to a lower finished grade. This requires a taller and higher class of poles, as well as more anchors and guying to support them.

d) Please refer to Tables 1 (Guelph Line to Kerns Road) and Table 2 (Northampton Boulevard to Guelph Line) below for a project schedule and cost breakdown of each section.

Table 1

Guelph Line to Kerns Road				
Quarter	Key Milestones	Gross Capital Expenditures	Capital Contributions	Net Capital Expenditures
Q2 2025	Cost sharing agreement with Region, finalize design	12,181	-	12,181
Q3 2025	Material procurement, contract award, start of construction	4,576,883	- 2,198,739	2,378,144
Q4 2025	End of construction, energization	4,589,064	- 2,198,739	2,390,325
	2025 Total	9,178,128	- 4,397,477	4,780,651

Table 2

Northampton Boulevard to Guelph Line				
Quarter	Key Milestones	Gross Capital Expenditures	Capital Contributions	Net Capital Expenditures
Q1 2026	Final design and approval, material procurement, start of construction	1,896,804	- 1,129,542	767,262
Q2 2026	End of construction, energization	1,896,804	- 1,129,542	767,262
	2026 Total	3,793,609	- 2,259,084	1,534,525



- e) No, based on currently available information BHI does not anticipate any further delays to the Dundas Street Road Widening project (Northampton Boulevard to Guelph Line and Guelph Line to Kerns Road sections).
- f) BHI will determine any potential credits owing to customers regarding the 2025 ICM project when 2025 actual results are available.

Staff-99**Fixed asset - Capitalization****Ref 1: BHI_IRR_Staff_07242025, 2-Staff-27****Ref 2: APH (Accounting Procedures handbook Dec 2011), Article 410, Part a & b****Ref 3: Chapter 2 Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications, December 9, 2024, Section 2.2.2, p.18****Preamble:**

In Ref 1, Burlington Hydro states that its assets do not meet the definition of a qualifying asset, nor are the borrowing costs directly attributable to the acquisition, construction or production of that asset. It also states that the interest costs associated with the debt cannot be directly attributed to a specific asset. Burlington Hydro expenses interest on long-term debt in USoA 6605 which is not included in any components of revenue requirement.

Question(s):

- a) Please confirm Burlington Hydro's practice of not capitalizing interests has been agreed upon by the external auditor and clarify whether Burlington Hydro has adopted this accounting policy in its previous cost of service applications under MIFRS. If not, please elaborate further.
- b) Please provide the nature of USoA 6605 since it is not included in APH of Ref 2. Please update the evidence as applicable.

Response:

- a) BHI confirms that its practice of not capitalizing interests has been agreed upon by its external auditor (refer to page 18 of BHI's 2024 Audited Financial Statements filed as Appendix G to Exhibit 1 of the Application). BHI has adopted this accounting policy in its previous cost of service applications under MIFRS.
- b) BHI's response to 2-Staff-27 contained a typo related to the USoA. The answer should have stated that "BHI expenses interest on long-term debt in USoA 6005..." not USoA 6605. No update to the evidence is required.

Staff-100

Revenue Impact – UsoA 1611

Ref 1: Chapter2Appendices_2BB_Service Life_07242025, 2BA

Ref 2: BHI_IRR_Staff_07242025, 2-Staff-28, Table 1

Preamble:

In Ref 1 & 2, OEB staff has compiled Table (A) as below, showing the difference of revenue impact between Ref 1 and Ref 2.

Table (A): Comparison of Useful Lives

USoA 1611	2026 Test Year Capital Additions	2026 Test Year Accumulated Depreciation Additions	Amount included in Revenue requirement 2026 (RRWF)
Ref 1 (a)	611,120	1,019,118	1,154,982
Ref 2 (b)	5,308,751	3,429,987	594,438
Ref 2 (c)	5,308,751	5,211,156	247,621
Variance (b-a)	4,697,631	2,410,869	(560,544)
Variance (c-a)	4,697,631	4,192,038	(907,361)

Question(s):

- a) Please explain the variance identified in the Table (A) above
- b) Please show the calculation of the amount in Table 1 of Ref 2.
- c) Please confirm whether USoA 1611 include both 5Y useful life assets and 10Y useful life assets.
 - i. If c) is confirmed, please provide worksheet to show the calculation of the depreciation amount based on different useful lives in USoA 1611 and reconcile to Ref 1.

Response:

- a) BHI's response to 2-Staff-28c) provided capital additions and accumulated depreciation on a cumulative basis for the affected CIS and GIS assets, instead of for USoA 1611 on a 2026 Test Year basis.

BHI provides the impact on a 2026 Test Year basis for USoA 1611 in Table 1 below.
BHI provides the impact using cumulative additions and depreciation for the GIS and CIS assets in Table 2 below, as provided in its response to 2-Staff-28.

The amount included in revenue requirement in 2026 of \$1,154,982 in Table (A) above does not include the impact of deemed debt or the PILs impact of the change to deemed equity. BHI includes the impact to revenue requirement as a result of the change in deemed debt and PILs in both tables below (note in BHI's response to 2-Staff-28c) it did not include the impact to PILs in error). The impact to revenue requirement before PILs is \$346,817 as identified in Table 1 of BHI's response to 2-Staff-28c).

The variance in revenue requirement, including deemed debt and PILs, using both methods of presentation is \$371,425 i.e. revenue requirement in proposed rates is \$371,425 higher than if BHI had depreciated its CIS and GIS assets using a 5-year useful life from 2022-2026.

Table 1 – 2026 Test Year (OEB-Staff presentation)

USoA 1611 2026 Test Year	2026 Test Year Additions	2026 Test Year Deprn	Amount Included in Revenue Requirement							Total
			2026 Deprn	Deemed Equity	OEB-Staff- Calc	Deemed Debt	Rounding	2-Staff-28	PILS	
Ref 1a) - Currently in Proposed Rates	\$611,120	\$1,019,118	\$1,019,118	\$135,864	\$1,154,982	\$97,992	\$74	\$1,253,048	\$48,985	\$1,302,033
CIS and GIS at 5 yrs	\$611,120	\$789,842	\$789,842	\$67,615	\$857,457	\$48,767	\$7	\$906,231	\$24,377	\$930,609
Difference	\$0	\$229,276	\$229,276	\$68,249	\$297,525	\$49,225	\$67	\$346,817	\$24,608	\$371,425

**Table 2 – 2026 Cumulative Additions and Depreciation (2-Staff-28 c) presentation)**

CIS/GIS 2026 Cumulative	2026 Cumul. Additions	2026 Accum Deprn	Amount Included in Revenue Requirement							
			2026 Deprn	Deemed Equity	OEB-Staff- Calc	Deemed Debt	Rounding	2-Staff-28	PILS	Total
CIS and GIS Currently in Proposed Rates	\$5,308,750	\$3,429,987	\$463,583	\$75,980	\$539,563	\$54,801	\$74	\$594,438	\$27,394	\$621,832
CIS and GIS at 5 yrs	\$5,308,750	\$5,211,158	\$234,307	\$7,731	\$242,038	\$5,576	\$7	\$247,621	\$2,786	\$250,407
Difference	\$0	(\$1,781,171)	\$229,276	\$68,249	\$297,525	\$49,225	\$67	\$346,817	\$24,608	\$371,425

- b) BHI provides a detailed calculation of the amount in Table 1 of Ref 2 (2-Staff-28) as CQ_Attachment_Staff-100, Tab “Staff-100b) and 100c)”. The amounts included in BHI’s response to 2-Staff-28 are highlighted in green. A summary calculation is also provided in Tab “Staff-100a) Calculation”.
- c) BHI confirms that USoA 1611 includes both 5Y useful life assets and 10Y useful life assets.
- i. BHI provides a worksheet to show the calculation of the depreciation amount based on different useful lives in USoA 1611 as CQ_Attachment_Staff-100, Tab “Staff-100b) and 100c)”. Column Q represents the depreciation included in rates for USoA 1611. The amounts highlighted in orange balance to OEB Appendix 2-BA (Ref 1).

Staff-101

ICM

Ref 1: Chapter2Appendices_2BB_Service Life_07242025, 2BA

Ref 2: Attachment 2_2025 ICM Model_BHI_20250124

Preamble:

In Ref 1, OEB staff notes Burlington Hydro moved total ICM assets (\$4.7M) from 2025 to 2026 capital base.

	2025		2026	
	Cost (ICM)	Accumulated Depreciation	Cost (ICM)	Accumulated Depreciation
1830 - Poles, Towers & Fixtures	-2,516,898	31,461	2,516,898	-62,922
1835 - Overhead Conductors & Devices	-1,370,603	23,137	1,370,603	-46,274
1855 - Services (Overhead & Underground)	-874,842	9,713	874,842	-18,347
Total	-4,762,343	63,772	4,762,343	-127,544

Question(s):

- Please explain the rationale of this practice observed by OEB staff.
- Please confirm whether 2025 capital additions (column E) in Ref 1 includes this \$4.7M ICM cost.
- Please confirm whether 2026 capital additions (column E) in Ref 1 includes this \$4.7M ICM cost.
- Please confirm there is no double counting of this \$4.7M ICM in both 2025 and 2026.

Response:

- The 2025 capital additions (column E) in Ref 1 included additions related to the approved 2025 ICM project. BHI removed these costs from the Closing Balance through a reduction in the ICM column (column G) to reflect that the additions are not yet



approved to be added into rate base. BHI is proposing to include these capital additions in rate base through an addition to the ICM column (column G) in the 2026 Test Year.

BHI applied the same rationale to Accumulated Depreciation. This is consistent with BHI's approach in its 2021 Cost of Service application¹.

- b) BHI confirms the 2025 capital additions (column E) in Ref 1 include the \$4.7M ICM cost.
- c) The 2026 capital additions (column E) in Ref 1 do not include the \$4.7M ICM cost.
- d) BHI confirms there is no double counting of the \$4.7M ICM in either 2025 or 2026.

¹ EB-2020-0007, App.2-BA_Fixed Asset Cont

Staff-102**Vehicles****Ref 1: Response to 2-Staff-23****Ref 2: IR_Attachment_2-Staff-23d_BHI_07242025****Question(s):**

- a) Is Burlington Hydro proposing to repair or replace single bucket truck T22 in the 2026 Test Year? If Burlington Hydro is replacing the vehicle, please state the need for replacement as the Matrix Score value is 16.

Response:

- a) BHI incorrectly identified that the single bucket truck T22 would undergo a “repair” instead of a “modification” in the 2026 Test Year for \$51,000. This expenditure represents modifying truck T22 with an electronic Power Take Off (ePTO), which will enable it to operate more efficiently and sustainably. Single bucket truck T22 is not being replaced in the 2026 Test Year.

Staff-103

Buildings

Ref 1: Exhibit 2 – Appendix O

Ref 2: Response to 2-Staff-24

Question(s):

- a) Please specify what projects from the 2021 Building Condition Assessment will be completed during the forecast period. Please provide the updated costs associated with each project if available to Burlington Hydro.
- b) Please provide the costs of the North and South parking lot projects individually.
- c) Please provide the 'Needs Assessment' for the projects referenced in 2-Staff-24 part a.

Response:

- a) BHI provides a list of projects from the 2021 Building Condition Assessment, as well as the 2024 Asset Condition Assessment and 2024 Security Assessment Report, that will be completed during the forecast period in Table 1 below. There is no change to the costs provided in BHI's response to 2-Staff-24 a).

Table 1

Program	2026 Test Year	2027	2028	2029	2030
1340 Brant St. Replacements	\$275,400	\$239,200	\$265,250	\$162,300	\$165,600
	\$234,600	\$0	\$0	\$0	\$0
North Parking lot	\$0	\$124,800	\$127,320	\$0	\$0
HVAC System	\$32,640	\$33,280	\$33,952	\$34,624	\$17,664
Total Projects from the 2021 Building Assessment	\$542,640	\$397,280	\$426,522	\$196,924	\$183,264
1328 Brant St. MS building	\$10,200	\$10,400	\$10,610	\$10,820	\$11,040
Distribution Stations	\$24,480	\$24,960	\$31,830	\$32,460	\$33,120
Total Projects from the 2024 Asset Condition Assessment	\$34,680	\$35,360	\$42,440	\$43,280	\$44,160
	\$66,300	\$10,400	\$10,610	\$10,820	\$11,040
Total Projects from the 2024 Security Assessment Report	\$66,300	\$10,400	\$10,610	\$10,820	\$11,040
Remaining Projects	\$227,460	\$101,920	\$103,978	\$84,396	\$59,616
Total Projects	\$871,080	\$544,960	\$583,550	\$335,420	\$298,080



- b) BHI provides the costs of the North and South parking lot projects individually in Table 1 below.

Table 1

Description	2026	2027	2028	Total
South Parking lot	\$127,500	\$0	\$0	\$127,500
North Parking lot	\$0	\$124,800	\$127,320	\$252,120
Total	\$127,500	\$124,800	\$127,320	\$379,620

- c) BHI provides the needs assessment for the projects referenced in 2-Staff-24 a) as follows:

South Parking lot

The expansion of the visitor parking lot is driven by the need to accommodate increased visitors, contractors/vendors, and additional staff to BHI's head office. BHI updated its internal policy to require all non-employee personnel to use the visitor parking lot and the South entrance to help maintain appropriate safety and security protocols.

HVAC System

Expenditures above the amounts identified in the 2021 Building Condition Assessment are based on condition (one unit has failed), age (units identified for replacement are beyond their expected service lives) and ongoing maintenance and repair costs. To pace these expenditures, BHI included replacement of two HVAC units each year in the forecast period.

1340 Brant St. Upgrades

This investment is based on the need to add new office space and workstations to accommodate planned increases in Full-Time Equivalents (FTEs), per Section 4.3.1.1 of Exhibit 4.

Staff-104**Subdivisions****Ref 1: Response to 2-Staff-22****Question(s):**

- a) Please provide the actual and forecasted number of buybacks Burlington Hydro assumed each year from 2021 to 2025.

Response:

- a) BHI provides the actual and forecasted number of buybacks (units) it assumed each year from 2021 to 2025 in Table 1 below.

Table 1

Subdivision Buybacks (Units)	2021	2022	2023	2024	2025
Forecast (EB-2020-0007)	300	300	300	300	300
Actual*	0	0	0	170	411

*2025 = forecast

Staff-105

Ref: 3-Staff-36

Question(s):

- a) Can you explain how you leveraged these sources and demonstrate the workings of how 15% was calculated?

Response:

- a) The 15% figure is based on judgement and is not the result of a specific calculation. Data from the NRCan National Energy Use Database is summarized in Table 1 below and shows approximately 10% of the increase in home heating stock in 2022 is due to heat pumps. Discussion of home heating from the Burlington Distribution System Sustainability Plan and the IESO's Pathways to Decarbonization report indicate heat pump adoption is expected to increase, and as such a 50% increase over historic adoption (for a total home heating conversion rate of 15%) was incorporated into the load forecast.

Table 1

Heating Stock (thousands)							
		2017	2018	2019	2020	2021	2022
Total Heating Stock	Total	5,575	5,651	5,734	5,831	5,936	6,034
	Yearly Increase		76	83	98	105	98
Heat Pump	Total	77.9	84.9	91.9	101.4	111.3	121.3
	Yearly Increase		7.0	7.0	9.5	9.9	10.1
Heat Pump % of Yearly Increase			9.2%	8.5%	9.7%	9.4%	10.3%

Staff-106**Ref: 4-Staff-40 (b,c,d)**

Question(s):

- a) Please explain how 261 service connection requests in 2025 to date are forecasted to increase from 261 to 1,091.
- b) Please confirm if there has been a trend in historical actuals for the number of service connection requests to increase disproportionately in the latter half of previous years.
- c) In response d(iii), Table 4, Burlington Hydro provides the number of OT hours from 2024 to 2025 actuals. Please explain why there is an inverse relationship between OT hours for the Engineering Technician role and the rise in customer service requests.

Response:

BHI identified an error in the forecasted number of connections and connection requests in the following IR responses, and has refiled corrected versions of these IR responses as CQ_Attachment_Staff-106:

- 4-Staff-40
 - 4-Staff-42
 - 4-Staff-51
 - 2-Intervenor-34
-
- a) Forecasted 2025 connection requests were based on a linear regression analysis using 2021-2024 actuals (per 4-Staff-42) and did not incorporate 2025 YTD results.
 - b) BHI has not analyzed the trend in historical actuals for the number of service connection requests in the first half vs. second half of previous years. However, BHI received 93 requests in the month of July 2025 as compared to an average of 44 requests per month in the first six months of 2025.
 - c) Customer connection service requests vary considerably in terms of scope, complexity, level of customer interaction required and time to connection. The OT hours, therefore, do not have a direct correlation with the number of connection requests received by BHI during the subject period.

Staff-107**Ref: 4-Staff-42**

Question(s):

- a) Please provide an explanation for why the Engineering Clerk and Locate Clerk have not logged any OT hours, despite the increase in actual and forecasted locate requests indicated in Table 2.

Response:

- a) Overtime work is voluntary for unionized staff including for the Engineering Clerk and Locate Clerk. To ensure compliance with Ontario One Call regulations and avoid the risk of administrative penalties,¹ the increased locates workload has been managed by reprioritizing and deferring other engineering tasks carried about by the Engineering Clerk and Locates clerk, and by incurring overtime at the management level to supplement the capacity of the clerks (e.g. complete locates overflow work that the clerks cannot execute within normal business hours, and complete other clerical engineering tasks such as responding to customer inquiries related to service connections and upgrades, scheduling service appointments with customers, processing internal engineering documents, coordinating permits, site plan, zoning and committee of adjustment processing, and responding to third-party (i.e. Electrical Safety Authority) inquiries.

¹ These regulations impose strict timeline requirements on LDCs to respond to standard locates within 5 business day and complex/multi-address locates within 10 business days in order.



Staff-108

Ref: 4-Staff-44(c)

Question(s):

- a) In response c to the above staff interrogatory, Burlington Hydro outlined the reasoning for the increased workload for the Communications Advisor role. Please provide figures for the growth in Burlington Hydro's social media following, and clarify how a rise in social media following results in the need for a higher volume of content to be created.

Response:

- a) BHI has experienced a sustained increase in its social media following across all major platforms. As of August 2025, Burlington Hydro's combined follower count has grown by 31.6% compared to 2022. This includes:
- X: Growth of 24% driven by updates on power outages and restoration efforts.
 - LinkedIn: Growth of 87% driven by expanded community engagement, participation in community events and corporate updates such as infrastructure investments.
 - Instagram: Growth of 212%, supported by visual storytelling and safety campaigns.

This growth is driven by a shift in how BHI's customers and stakeholders prefer to receive information – as they increasingly look for digital-first communications. This can be seen in the results of BHI's 2024 Customer Service Survey in which growth in customers reaching out on digital channels grew by 23% while inquiries via telephone declined by 9%.

A larger audience requires more frequent and varied content to maintain relevance and increase visibility to ensure customers receive information about BHI and its services. BHI customers place high value on content that is both informative and timely such as updates on power outages, restoration timelines, energy-saving tips, emergency preparedness and safety reminders. Educational posts about new programs, billing options, and sustainability initiatives help customers make informed choices. Visual storytelling, such as behind-the-scenes looks at field crews or infographics explaining complex topics, further engages the community and builds trust. BHI continues to review and expand its posting frequency, and diversify its content to meet these expectations.

Operating across multiple corporate accounts, the Communications Advisor must also customize messaging to different platforms and audiences, while maintaining a



consistent brand voice. This has resulted in an increase in content creation activity of 30.4% from 2022 to 2024 (the last full year of data).

Overall, the growth in BHI's social media following has led to a proportional increase in the Communication Advisor's efforts to develop a higher volume of timely, relevant and targeted content across its four corporate social media channels.

Staff-109**Ref: 4-Staff-45(a)**

Question(s):

- a) Burlington Hydro states that financial planning, regulatory compliance and capital tracking related responsibilities are currently dispersed among various roles in the Finance department, and that the utility does not track OT hours for these positions:
- Controller
 - Financial Accountant,
 - Financial Analyst
 - Accountant, Financial and Regulatory
 - a temporary Co-Op student

Please confirm whether any OT hours have been assigned to the above roles (aside from the 65-1,300 hours logged by the co-op student) in regard to the financial planning, regulatory compliance, and capital tracking functions that the proposed Financial Analyst would assume.

Response:

- a) BHI confirms that OT hours have been assigned to all of the roles identified above (aside from the 650-1,300 hours logged by the co-op student) in regard to the financial planning, regulatory compliance, and capital tracking functions that the proposed Financial Analyst would assume.

Staff-110**Ref: 4-Staff-50 (b)****Question(s):**

- a) In its response, Burlington Hydro indicated it had redistributed key responsibilities among the current team (three manager-level Distribution Engineers and the Vice-President, Engineering Services & Network Operations) and listed the specific responsibilities taken on by the other staff during the vacancy. Where possible, please provide OT hours for each role indicated above associated with the specific responsibilities outlined in the response.

Response:

- a) BHI does not track overtime hours for the three manager-level Distribution Engineers and the Vice-President, Engineering Services & Network Operations.

Staff-111**Ref: 4-Staff-57**

Question(s):

- a) In its response to the above interrogatory, Burlington Hydro estimated that 15 FTEs have had work assigned which is associated with OEB policy consultations and initiatives, but indicated that the requested information is too granular to provide an accurate response. Please provide the number of OT hours for these 15 FTEs have logged each year from 2021 to 2024 and YTD 2025.

Response:

- a) The number of OT hours from 2021 to 2024 and YTD 2025 for these 15 FTEs is unavailable. These 15 FTEs are primarily non-union positions for which BHI does not log unpaid overtime.

Staff-112**Ref: 4-Staff-63(d)**

Question(s):

- a) Burlington Hydro indicated that the absence of a dedicated Engineering Supervisor, Energy Transition, some of the tasks identified in part (a) of its response are distributed across existing portfolios within the engineering department. Please provide an overview of which tasks were assigned to which department or role.

Response:

- a) BHI identifies the tasks that are distributed across existing portfolios within the engineering department as follows:
- Strategic Planning and Integration: System Planning and Engineering Design groups
 - Project Execution: Engineering Design and Customer Connections, Key Accounts groups
 - Stakeholder Engagement: Engineering Design and Customer Connections, Key Accounts groups
 - Policy and Regulatory Compliance: Engineering Design and Customer Connections, Key Accounts groups

The remaining tasks require resourcing in the form of the Supervisor, Energy Transition Integration and include centralized project oversight, technical leadership, data and performance monitoring, and team leadership and development.

Staff-113**Ref: 4-Staff-66****Question:**

- a) In response b, Burlington hydro indicates that effectively addressing employee turnover is a critical component of this role, citing a high average turnover rate. However, in its response to 4-Staff-39 (responses to b-c-d, Table 1), Burlington Hydro provides updated turnover figures for 2025, indicating that employee turnover continues to trend downward. Please reconcile the stated need for the HR role in the context of declining turnover.

Response:

- a) BHI has consistently experienced a double-digit average turnover rate over a period exceeding five years. It has experienced a wave of retirements and unwanted turnover resulting in over 75% of its workforce turning over (refer to page 221 of Exhibit 4).

Although turnover has recently trended downward, it is still significant and disruptive to the organization (see Table 1 of 4-Staff-39). Further, the declining trend is not necessarily indicative of the future. To maintain turnover levels sustainable in a labour market that is expected to be increasingly competitive due to labour shortages and growth, BHI must take proactive steps to manage turnover risk and impact to the organization, including enhancing processes, procedures and HR programs such as succession planning, workforce planning and training to ensure knowledge transfer takes place prior to turnover occurring.

Delivering these proactive HR initiatives effectively while also addressing other incremental requirements in this portfolio, requires the support of another HR professional. Other requirements in this portfolio driving the need for an additional resource include the proposed addition of 14 FTE in 2026, as identified in Exhibit 1 at pp. 40-42 and Exhibit 4 at pp. 193-197.

Managing a larger workforce entails higher work volumes related to position analysis, workforce planning, employee engagement, performance management, recruitment and retention activities, training and development programs, employee relations and issues resolutions, and change management, particularly in the context of technological advancements and the shift to remote work as a result of the COVID-19 pandemic.

Staff-114

PILs Model

Ref 1: BHI_IRR_Staff_07242025, 6-Staff-76, Table 2

Ref 2: Attachment_2026 PILs Workform_BHI_07242025, B8_Sch8_CCA Bridge

Ref 3: Attachment_OEB_Chapter2Appendices_BHI_07242025, 2BA, Y2025

Preamble:

Per Ref 1, 2 & 3, OEB staff has reconciled 2025 capital additions between PILs model (Schedule 8) and Appendix 2BA (before CWIP addition and excluding land), which shows the variance from Ref 1.

Table (1): Reconciliation of Capital Additions between PILs (Sch8) & 2BA

	Ref 1 (a)	OEB Staff Notes
Capital Additions per Appendix 2-BA	17,903,861	There is variance of \$203,215 from Ref 3 since Burlington Hydro included CWIP amount.
Capital Additions per the PILs Model	12,715,489	There is variance of (\$140,700) from Ref 2 since Burlington Hydro included column H adjustment

Question(s):

- Please confirm OEB staff's observation.
- Please explain, reconcile and update the 2025 capital addition amount between Ref 2 and Ref 3

Response:

- BHI confirms that the capital additions per Appendix 2-BA identified in Table 2 in 6-Staff-76 were \$17,903,861 and should have been \$17,700,646 to incorporate WIP of \$203,215.

BHI confirms that the capital additions per the PILS model identified in Table 2 in 6-Staff-76 of \$12,715,489 included the column H adjustment of (\$140,700).



- b) BHI provides an updated Table in response to 6-Staff-78 below as Table 1. BHI files an updated PILS Model as Attachment_2026_PILS_Workform_BHI_08112025 to move the WIP of \$203,215 from column E to Column H. There is no impact to the PILS calculation.

Table 1 – Revised Table 2 (6-Staff-78)

Description - Clarification Questions (Staff-114)	2025	2026
Capital Expenditures per Appendix 2-AB	\$17,903,861	\$24,870,805
Add/(Deduct) WIP	-\$203,215	\$46,195
Capital Additions per Appendix 2-BA (Ref 3)	\$17,700,646	\$24,917,000
Deduct: Capitalized Overhead in 2-BA deducted for tax purposes	-\$289,483	-\$289,483
Deduct: SR&ED Capitalized in 2-BA deducted for tax purposes	-\$136,546	-\$136,546
(Deduct)/Add: Adjustment to Class 47 (ICM Dundas Road Widening)	-\$4,762,343	\$4,762,343
Capital Additions including CCRA refund of \$140,700	\$12,512,274	\$29,253,314
Add: HONI CCRA Refund captured in column H of PILS model	\$140,700	0
Capital Additions per PILS model (column E) (Ref 2)	\$12,652,974	\$29,253,314

Staff-115

Accelerated CCA & Smoothing Mechanism

Ref 1: BHI_IRR_Staff_07242025, 6-Staff-78, Table 2

Question(s):

- a) Please complete the Table below (compiled by OEB staff) based on forecast CCA amount from 2028 to 2030.

	2028 Forecast	2029 Forecast	2030 Forecast	Cumulative Total
CCA Legacy (no AIIP) (a)				
CCA Bill C-97 (with AIIP) (b)				
CCA Difference (c=b-a)				d
Take 1/5 of Difference (e=d/5)				
Income tax (f=e*26.5%)				
Gross up (g=f/73.5%)				
2026 PILs expense (h) – Ref 1	925,602			
Total Revenue Requirement (g+h)				

Response:

- a) BHI provides the completed table as Table 1 below.

Table 1

Description	2028 Forecast	2029 Forecast	2030 Forecast	Cumulative Total
CCA Legacy (no AIIP) (a)	\$11,998,791	\$13,348,517	\$13,437,396	\$38,784,703
CCA Bill C-97 (with AIIP) (b)	\$13,495,866	\$14,139,971	\$13,542,520	\$41,178,357
CCA Difference (c=b-a)	\$1,497,075	\$791,454	\$105,124	\$2,393,654
Take 1/5 of Difference (e=d/5)	\$478,731			
Income tax (f=e*26.5%)	\$126,864			
Gross up (g=f/73.5%)	\$172,604			
2026 PILs expense (h) – Ref 1	\$925,602			
Total Revenue Requirement	\$1,098,206			

Staff-116**DVA Continuity****Ref 1: Attachment_DVA_Continuity_Schedule_BHI_07242025****Question(s):**

- a) Please confirm the most recent OEB prescribed interest rate has been used in calculating the carrying charges in Ref 1.

Response:

- a) BHI has incorporated the OEB prescribed interest rates up to Q2 2025 in calculating the carrying charges in Ref 1.

Staff-117**Group 1****Ref 1: BHI_IRR_Staff_07242025, 9-Staff-82****Preamble:**

Per Ref 1, Burlington Hydro states that it is currently still in the process of verifying the accuracy of the automated settlement calculations of which the targeting completion is by the end of 2025 and hasn't identified any material adjustments to Group 1 accounts due to the new process up to this point.

Question(s):

- a) Please confirm whether Burlington Hydro has identified any material adjustment in the IESO settlements and Group 1 DVAs.

Response:

- a) BHI has not identified any material adjustments in the IESO settlements and Group 1 DVAs due to the new process up to this point.

Staff-118**Customer choice****Ref 1: BHI_IRR_Staff_07242025, 9-Staff-90****Preamble:**

Per Ref 1, Burlington Hydro proposes to keep the Customer Choice Account open in case it incurs any incremental costs directly attributable to future code amendments made in response to

Customer Choice initiatives.

OEB staff notes Burlington Hydro has already included the forecast amount up to December 2025 and the implementation starts from 2020 which has been 5 years.

Question(s):

- a) Please provide the thought on discontinuing the account, given that the account was established to record the incremental costs associated with the customer billing choice initiative in 2020.

Response:

- a) BHI withdraws its request to continue the Customer Choice Account.

Staff-119

Impacts Arising from the COVID-19 Emergency

Ref 1: BHI_IRR_Staff_07242025, 9-Staff-93, Table 1

OEB staff has compiled the following Table (B) showing the Means Test calculation:

Item	2020	2021	Calculation of 2021 ROE
OEB approved ROE % (Ref 1)	9.36%	8.68%	9.36% (Jan~Apr)/12*4 + 8.34%(May~Dec)/12*8 = <u>8.68%</u>
Less: 300bps (Ref 1)	3.00%	3.00%	
Allowed ROE % (Ref 1)	6.36%	5.68%	8.68% - 3.00% = <u>5.68%</u>
Achieved ROE % (Ref 1)	1.49%	6.44%	4.57%(Jan~Apr)/12*4 + 7.38%(May~Dec)/12*8 = <u>6.44%</u>
Means Tests	Pass	Fail	

OEB Staff notes that the Means Tests for entire 2021 failed on weighted average basis per Table (B) above.

Question(s):

- Please confirm OEB staff's observation in Table (B) or revise the table as applicable.
- If confirmed, please update the Account 1509 balance by excluding the 2021 amount.

Response:

- BHI is not able to confirm OEB's staff's observation in Table B. BHI's rate setting period during COVID was from May 1 to Apr 30. BHI's rate structure changed May 1, 2021. As such BHI does not think it is appropriate to take the average of the ROE from two different rate setting periods to determine the deemed and actual ROE for the threshold test. Each rate-setting period should be assessed individually.



BHI respectfully disagrees with OEB staff's methodology used in Table B for the following reasons:

OEB approved ROE %

OEB staff's calculation uses a weighted average of the OEB approved ROEs for 2021. However, based on BHI's interpretation of the OEB's COVID-19 Deferral Account Report (issued June 17, 2021), specifically Section 4.2.1, the means test is to be applied by comparing the achieved ROE to the OEB-approved ROE less 300 basis points, as applicable to the claim period.

"The OEB will apply a means test to recoveries in the Account based on achieved ROE compared to a utility's OEB-approved ROE less 300 basis points."

The report does not reference or suggest the use of a weighted average of the OEB-approved ROEs for split-year calculations. Therefore, BHI applied the OEB-approved ROE applicable for the relevant periods (i.e., January to April 2021) during which the COVID-19 amounts were incurred and are being claimed.

Achieved ROE %

Similarly, BHI does not agree with the approach of using a full-year weighted average achieved ROE that includes the May to December 2021 period. As noted in its response to 9-Staff-93, no amounts related to May–December 2021 are being claimed under the COVID-19 deferral account.

Calculating the weighted average achieved ROE 2021 by including the period (May to December) which is not subject to recovery creates a mismatch between the basis of the means test and the actual claim period.

b) Not applicable.

Staff-120

Capital Additions Dundas Street Road Widening Project - Revenue Requirement

Differential Variance Account (CVA1)

Ref 1: BHI_IRR_Staff_07242025, 9-Staff-94, Figure 1

Ref 2: Exhibit 9, section 9.1.11, Table 27

Preamble:

Per Ref 1, Burlington Hydro states that the increase of 510K was reduced by a decrease in 2020 resulting in a total expenditure increase was 225K over 2020-2021. It also states that \$3,035,948 represents the amount tracked through CVA1.

Question(s):

- a) Please confirm the \$225k decrease mentioned above has been applied to the actual project cost.
 - i. If confirmed, please update the Actual Additions in Ref 2 to reflect the decrease of \$225k
 - ii. If not confirmed, please explain why not

Response:

- a) The \$225K in Ref 1 is an increase, not a decrease. The 2020 Bridge Year forecast decreased and the 2021 Test Year forecast increased for a net forecasted increase of \$225K over the 2020-21 period. BHI provides the changes for forecasted expenditures from its application to its interrogatory responses from its 2021 Cost of Service application in Table 1 below.

Table 1

Dundas St. Road Widening	2020 Bridge Year	2021 Test Year	Total
Application (EB-2020-0007)	350,194	2,526,183	2,876,378
Interrogatory responses (EB-2020-0007)	65,275	3,035,948	3,101,223
Change	- 284,919	509,765	224,845



- i. The forecasted decrease of (\$284,919) in the 2020 bridge year was reflected in Appendix 2-AA of the Chapter 2 Appendices filed with BHI's settlement proposal¹. 2020 actual expenditures are not reflected in the Actual Additions in Ref 2 because CVA1 tracked budgeted vs. actual capital additions in 2021 only. The increase of \$509,765 in the 2021 Test Year was a forecast. Actual incurred capital expenditures for 2021 are included in the Actual Additions of \$517,315 in Ref 2.
- ii. Please see response to part a i) above.

¹ EB-2020-0007, Attachment_Main_OEB_Chapter2Appendices_BHI_Revised, February 1, 2021

ED-CQ-1**Reference: 2-Intervenor-33 (b) and (d)****Question(s):**

Exhibit 2-Intervenor-33 (b) and (d) indicate that BHI does not charge residential customers to upgrade their service up to 200 amps. Please confirm whether this includes there being no charges for (a) the connection/disconnection needed to replace the panel and (b) the cost to upgrade the conductor serving the home (where applicable). If there are charges for those amounts, please let us know what they are.

Response:

BHI confirms it does not charge for (a) the connection/disconnection needed to replace the panel and (b) the cost to upgrade the conductor serving the home (where applicable) when upgrading a service to 200 amps as long as the scope of work falls within BHI's defined Basic Connection.

ED-CQ-2**Reference: 2-Intervenor-33 (f)****Question(s):**

Exhibit 2-Intervenor-33 (f) indicates that “[r]esidential service upgrades are completed in an average of 16 weeks for underground service and 8 weeks for overhead service.” That seems like a very long time to make a customer wait who wishes to upgrade their service panel, particularly in cases where all the utility needs to do is cut off the power and reconnect the power. Please explain why the wait is so long.

Response:

The majority of customer service upgrade requests involve more than the disconnect and reconnect of power associated with the simple changeout of a service panel or fuses on the panel. For the majority of customer service upgrade requests, BHI has to ensure that the new (upgraded) service meets the current safety standards as per Reg.22/O4 requirements and approved equipment (such as service conductor) meets customer requirements. This requires a site inspection by a qualified design/services technician, assessment of the size and condition of connection assets both on the customer and BHI side of the demarcation point, preparation of scope of work for BHI and the customer, design documents, locates, applicable permit approvals, followed by an offer to connect. Therefore, appointments are scheduled to ensure that all required conditions are met before the new service can be energized. This also allows the customer to prepare their equipment to receive the new service from BHI and obtain the necessary approvals from the safety authority (ESA).

For upgrades involving underground service, the timeline is generally longer as the work has to be coordinated with contractors specialized in civil construction works in addition to the electrical work by BHI.

Where it is determined that the existing BHI infrastructure can accommodate the service upgrade, BHI is typically able to accommodate the customer with a shorter timeframe for disconnection and reconnection of service.

ED-CQ-3

Reference: 2-Intervenor-34

Question(s):

Please provide a table and an explanation to reconcile Table 1 and Table 2 in 2-Intervenor-34. Those tables show a large disparity between new connections and connection requests.

Response:

Note: BHI identified an error in the forecasted number of connections and connection requests in the following IR responses, and has refiled corrected versions of these IR responses as CQ_Attachment_Staff-106:

- 4-Staff-40
- 4-Staff-42
- 4-Staff-51
- 2-Intervenor-34

BHI provides a response to ED-CQ-3 based on the corrected Tables 1 and 2 in 2-Intervenor-34.

Table 1 in 2-Intervenor-34 included forecasted new connections, whereas Table 2 in 2-Intervenor-34 included forecasted connection requests. Forecasted connection requests are higher than forecasted new connections because i) they include requests for upgrades which are not considered new connections, ii) they include MTSA connection requests in 2026 and 2027 that will not result in new connections until 2028 and 2029 because a system expansion is required, and iii) they include requests for connection where the customer decides not to proceed with the connection. BHI provides a reconciliation between the corrected versions of Table 1 and Table 2 in 2-Intervenor-34 in Table 1 below.

Table 1

Forecast	2025	2026	2027	2028	2029	2030
New Connections (2-Intervenor-34 a), Table 1)	524	612	700	1,253	1,341	
Connection Requests (2-Intervenor-34 c), Table 2)		1,783	1,941	2,099	2,257	2,415
Difference		1,172	1,241	846	916	
Connection Requests for Upgrades		686	743	765	788	
Major Transit System Area (MTSA) Connection Requests		465	465	-	-	
Connection Requested but Customer not Proceeding		21	33	81	128	

ED-CQ-4**Reference: 2-Intervenor-36 (f)**

Question(s):

Is BHI willing to assist customers in the ways outlined in 2-Intervenor-36 (f)?

Response:

Yes, BHI is willing to assist customers in the ways outlined in 2-Intervenor-36 f). BHI's ability to assist customers in all of these ways is dependent on, but not limited to, the following factors:

- Resource constraints – assisting these customers is contingent on BHI implementing its workforce management strategy of upskilling existing employees and creating new positions to ensure it has the capacity and knowledge to assist and educate customers;
- Investing in foundational technologies such as ADMS and smart field devices to modernize grid management capabilities in response to increased demand, electrification, and DER penetration;
- Distribution system factors such as available capacity;
- LDC roles and responsibilities within Stream 2 of the IESO's eDSM framework;
- Availability of incentives and eligibility criteria;
- Regulatory policy and guidelines; and
- EV uptake and (multi-unit residential building owner) customer interest.

ED-CQ-5**Reference: 2-Intervenor-37**

Question(s):

2-Intervenor-37 indicates as follows: “c) BHI has not yet made a determination on whether all new AMI 2.0 meters will be bidirectional or not. Having all meters as bi-directional carries higher maintenance and reverification costs in the future. All new AMI 2.0 meters will have the capability of being programmed and sealed as bi-directional.”

- a) Please elaborate on this response.
- b) Why is there a higher cost to maintain and verify bi-directional meters?
- c) Does the response mean that an AMI 2.0 meter could be installed without bi-directional capability but later updated to add that functionality without fully replacing it?
- d) Can these capabilities be added via a firmware update?
- e) All of the AMI 2.0 meters to be installed by Toronto Hydro will be bi-directional. Why is BHI potentially proposing something different?

Response:

- a) BHI is still evaluating new meters and their performance and has not made a final decision on the features and programming parameters of new meters. Having all meters as bi-directional could impact the data backhaul and contribute to mesh network data volumes.
- b) There are higher costs from Measurement Canada accredited test facilities for sealing a bi-directional meter since they have to run the same tests twice, once in each direction, resulting in added labour for the testing.
- c) Yes, AMI 2.0 meters could be installed without bi-directional capability but later updated to add that functionality without fully replacing the meter.
- d) Yes, certain capabilities including bi-directional channels can be programmed or enabled via an over the air firmware update.
- e) Please see BHI's response to part a).

ED-CQ-6**Reference: 2-Intervenor-40 (a)**

Question(s):

Why does BHI disagree with all of the recommendations set out in the report found at 2-Intervenor-40(a)?

Response:

The Energy Storage Feasibility Study (the Study) provided recommended next steps should BHI proceed with the deployment of the Battery Energy Storage System (BESS). The site considered in the Study (Fairview MS) is currently an active substation with customers connected to it. As such, due to operational factors, BHI is not able to proceed with the deployment of the BESS until customers have been converted to a 27.6kV supply and the substation has been decommissioned.

The intent of the study was to explore the feasibility, benefits, and potential challenges of integrating a BESS into BHI's grid infrastructure. BHI will revisit this study and assess the recommended next steps if/when it is ready to proceed with a BESS deployment at the Fairview MS, or elsewhere within its service territory.

ED-CQ-7**Reference: 2-Intervenor-46 (d) and (e)****Question(s):**

Please provide a full response to 2-Intervenor-46 (d) and (e). It is not clear if all projects of over \$2 million have undergone a NWS assessment. Also, the table requested in (e) remains pending.

Response:

In response to 2-Intervenor-46 d), BHI considered the applicability of NWS for all material projects (over \$2 million) which were the system expansions for the MTSA's and the Dundas St. road widening project. For all these projects an initial assessment was made to determine the feasibility of NWS and it was determined to be a non-viable option in all cases. As such a full NWS assessment was not carried out beyond the initial assessment.

In response to 2-Intervenor-46 e) please see Table 1 below for each project over \$2 million.

Table 1

Project	NWSs Considered	Initial Assessment	Viable Option	Third-Party Consultation
Dundas St. Road widening	DER / CDM	Mandatory requirement under the PSWHA (Public Service Works on Highways Act). Relocation of existing infrastructure, so DER/CDM are not viable alternatives.	No	None
MTSA – Aldershot GO	DER / CDM	Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable.	No	None
MTSA – Burlington GO	DER / CDM	Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable.	No	None
MTSA – Appleby GO	DER / CDM	Forecasted demand is significant requiring consistent, scalable capacity for new customers, where DERs/CDM would not be practical solutions due to the limitation in supporting new base load (unlike peak demand) and/or requiring complex modifications to the existing network. Need for extending physical infrastructure to serve new customers makes NWs non-viable.	No	None

ED-CQ-8**Reference: 8-Intervenor-137****Question(s):**

Page 7 of exhibit 8 indicates that BHI proposes to set the fixed monthly charge for GS>50 kW at the OEB ceiling for 2026. Please estimate the OEB ceiling for each subsequent year in the rate term on a best efforts basis or confirm that it will remain unchanged. Please comment on whether the fixed monthly charge for GS>50 kW is likely to increase over the board ceiling due to inflation during the rate term. This question related to 8-Intervenor-137.

Response:

BHI does not have sufficient information in 2027 to 2030 to forecast the OEB ceiling beyond the test year on a cost of service basis as it only has load forecast, cost allocation and revenue requirement information on a 2026 Test Year basis.

During the IRM term, BHI will inflate its revenues at OEB inflation (less its stretch factor). If BHI applies that same OEB inflation rate to the costs that underly the Customer Unit Cost per month - Minimum System with PLCC Adjustment calculation, the OEB ceiling is expected to increase at the same rate as BHI's rates. As such, the inflated fixed monthly charge for GS>50 kW will remain at the inflated OEB ceiling on an annual basis from 2027-2030 (based on OEB inflationary increases only – BHI will not be conducting a cost allocation study with actual costs and load during the IRM term).

ED-CQ-9**Reference: 8-Intervenor-139****Question(s):**

Exhibit 8-Intervenor-139 indicates that BHI charges a \$500 application fee for microgeneration connections. Please explain how BHI arrived at that amount, with fully detailed calculations and assumptions. Please explain how BHI is allowed to levy this charge when it is not a specific service charge approved by the OEB.

Response:

BHI charges a \$500 connection deposit for preparing an offer to connect a microgeneration facility in accordance with Section 5.3.7 of the OEB's Distributed Energy Resources Connections Procedures¹.

¹ Distributed Energy Resources Connections Procedures, Version 2.0, January 27, 2025, p13

ED-CQ-10**Reference: 8-Intervenor-139****Question(s):**

Exhibit 8-Intervenor-139 indicates that BHI charges \$1,500 in commissioning on average for microgeneration connections. This is unusual for micro connections. Please explain why BHI charges for commissioning for micro connections and what work the charge typically covers.

Response:

BHI clarifies that it only applies commissioning charges to microgeneration connections when the application includes battery storage installation and load displacement. This charge typically covers verification of the nameplate data provided by the Customer on the original application and approved Offer to Connect, equipment labeling, locating of the utility disconnect, anti-islanding testing, reverse power flow testing and any other required testing prior to connecting the DER to BHI's system.

BHI does not apply a commissioning fee to solar net metering microgeneration connections where no battery storage is installed, which is more than 90% of these connections.

ED-CQ-11**Reference: 8-Intervenor-139****Question(s):**

Exhibit 8-Intervenor-139 indicates that BHI charges a \$5,413 fee for CIAs for small and medium DER connections. Please explain how BHI arrived at that amount, with fully detailed calculations and assumptions. Please explain how BHI is allowed to levy these charges when they are not a specific service charge approved by the OEB.

Response:

BHI engages an Engineering Consulting firm in order to prepare the required Connection Impact Assessment for DERs greater than 10kW as it does not have the internal capacity to prepare these within prescribed timelines. The CIA Cost is a “pass through” charge from BHI’s consultant and reflects market rates for this type of service. BHI provides a breakdown of these costs in Table 1 below.

Table 1

Description	Cost
Data Collection and Preliminary Engineering	\$2,150.00
Detailed Engineering, Report Finalization, Project Management and Approvals	\$3,263.00
Total CIA cost	\$5,413.00

BHI applies variable connection charges in accordance with Section 3.1.6 of the DSC.

ED-CQ-12**Reference: 8-Intervenor-139****Question(s):**

Exhibit 8-Intervenor-139 indicates that BHI charges a \$5,413 fee for CIAs for small and medium DER connections. Most utilities charge considerably less for CIAs for small DER connections. Please justify BHI not doing so. Please justify BHI not have a simplified CIA fee category pursuant to recent amendments to the DSC and DERCP.

Response:

BHI engages an Engineering Consulting firm in order to prepare the required Connection Impact Assessment for DERs greater than 10kW as it does not have the internal capacity to prepare these within prescribed timelines. The CIA Cost is a “pass through” charge from BHI’s consultant and reflects market rates for this type of service..

The Connection Impact Assessment calculation and power flow analysis requires the same amount of work, regardless of the size of the DER, which is why BHI charges the same amount for small and medium DER connections.

BHI must comply with Hydro One requirements for the connection of all DERs greater than 10kW and provide an annual report of all connected DERs greater than 10kW with the short circuit contribution per connection, as per signed Threshold Agreements between Hydro One and BHI

BHI is in the process of finalizing a Simplified CIA Fee Category as described in the DERCP Version 2.

ED-CQ-13

Reference: 8-Intervenor-139

Question(s):

Please indicate how much BHI has collected over the current and previous rate terms in micro generation connection fees and CIA fees for small generation CIAs. Please provide a breakdown by type.

Response:

BHI provides the amounts collected over the current rate term in micro generation connection fees and CIA fees for small generation CIAs in Tables 1 and 2 below.

Table 1: Connection Fees for Small DERs (>10kW and <=500kW)

Year	# of Connected Small DERs	Total Connection Fee + CIA
2020	0	\$0
2021	1	\$40,000
2022	2	\$62,000
2023	0	\$0
2024	2	\$53,500
2025 YTD	4	\$21,652

Table 2: Connection Fees for Micro DERs (<10kW)

Year	# of Connected Micro DERs	Total Connection Fee + Application Fee
2020	4	\$2,741
2021	6	\$4,111
2022	22	\$15,074
2023	28	\$21,679
2024	34	\$30,844
2025 YTD	8	\$8,454

BHI is unable to provide the amounts collected in the previous (2014-20) rate term under the timelines for responding to clarification questions as this data is not readily available.

ED-CQ-14**Reference: 8-Intervenor-139**

Question(s):

Exhibit 8-Intervenor-139 indicates that BHI's Scada threshold was 10 kW in 2021. What is it now and why did it change?

Response:

BHI current Scada threshold is for DERs greater than 250kW. It was changed mainly to reduce the overall connection cost to customers for applications less than 250kW.

ED-CQ-15**Reference: 8-Intervenor-142****Question(s):**

Exhibit 8-Intervenor-142 seems to indicate that BHI assesses losses in transformer and conductor purchases by including loss-related specifications that must be met, but does not calculate an all-in lifetime cost of each alternative (e.g. different sized conductors, different transformer brands) in a way that includes the forecast cost of losses arising from each alternative. Please confirm whether we are interpreting this response correctly. If not, please provide clarification, addressing both conductors and transformers. If all in cost are accounted for, please provide an actual example of the relevant paperwork for a conductor and a transformer.

Response:

BHI confirms it does not calculate an all-in lifetime cost of each alternative in a way that includes the forecast cost of losses arising from each alternative.

ED-CQ-16**Reference: 8-Intervenor-140 (e)****Question(s):**

Please respond to 8-Intervenor-140 (e). If necessary, please provide a rough estimate of future costs over the rate term based on historical figures, along with underlying calculations.

Response:

BHI does not forecast losses (kWh), losses at peak (kW), or cost of losses to customers, but provides estimates on a best-efforts basis as CQ_Attachment_ED-16.

ED-CQ-17**Reference: 8-Intervenor-140**

Question(s):

Exhibit 8-Intervenor-140 describes a number of additional steps that BHI will be taking with respect to losses. Please provide a table listing those, including a column indicating when the step in question will be commenced and completed.

Response:

BHI's ability to implement loss reduction measures over the 2026-2030 period is dependent on the additional staffing and OM&A funding proposed in its Application¹, including the Supervisor - System Planning and Grid Modernization. Additionally, investments in SCADA/ADMS and smart field devices (intelligent switches) are critical for implementation of system loss mitigation and grid modernization strategy. BHI's Application contemplates the following timing with respect to additional steps to address losses:

Loss mitigation measures	Timing
Phase load balancing	On-going, demand driven (2026 and onwards)
Feeder reconfiguration	Based on system performance, quarterly or as needed (2026 and onwards)
Voltage conversion	Annually, as part of system renewal, where applicable (2026 and onwards)
System Optimization	Subject to implementation of ADMS / SCADA and integrated smart field devices (anticipated 2028 and onwards)

BHI will incorporate loss reduction measures as part of broader system improvement plans that consider asset condition, load, feeder congestion, and other operational priorities, the timing of which ultimately drives the additional steps BHI takes with respect to losses.

The Supervisor, System Planning and Grid Modernization will oversee the performance of regular power system analyses on vulnerable feeders, including system loss estimation using CYME software to support the above measures. Aligning the system loss reduction goals with

¹ EB-2025-0051, 8-Intervenor-142 a)

BHI's grid modernization objectives is critical to transition from legacy systems to advanced technologies like ADMS and SCADA, which enable real-time visibility, fault location analytics and predictive outage restoration. The Supervisor, System Planning and Grid Modernization will be directly responsible for evaluating emerging technologies and their impact on system performance/losses and executing the planned implementation. The ensuing capabilities would directly support loss mitigation by:

- Identifying grid weaknesses and optimizing dispatch decisions
- Improving outage resolution through automated fault detection and isolation
- Enhancing data quality for system planning and reliability performance tracking

ED-CQ-18**Reference: 8-Intervenor-144**

Question(s):

Please provide a response to 8-Intervenor-144. It will be very difficult to settle loss-related issues without that response.

Response:

Please see below for CIMA+ comments on what it would propose including in a further study during the next rate period to build on the learnings from its June 21, 2023 report, address any potential missing data or other gaps, and explore additional means to cost-effectively reduce distribution losses.

- 1) Update/validate CYME with latest SCADA/AMI (peak and typical), then screen specific feeders and rank by peak line-loss > 4%, and phase imbalance > 10% to produce a prioritized shortlist.
- 2) Evaluate feeders with >10% current imbalance for potential targeted load balancing, with emphasis on cost-effective cases.
- 3) Conduct additional feeder reconfiguration scenarios where the 2023 study showed potential. Run switching/supply-point transfer options with protection/voltage/loading checks and quantify loss reduction and operational impacts.

SC-CCC-1**2-Intervenor-20 and 2-Staff-28 (c)**

- a) Please provide a detailed description, and the underlying calculations, for Table 1 to 2-Staff-28(c).
- b) To the extent that the response to part (a) does not explain the following, please provide responses to the below questions.
 - i. Please provide the 2021 average rate base for each of the CIS and GIS assets separately.
 - ii. Please confirm that the 2021 average rate base (part (i)) was funded in 2021 rates based on a 20% depreciation rate.
 - iii. Please provide the 2021 depreciation expense (\$) reflected in revenue requirement related to the 2021 average rate base for the CIS and GIS assets/
 - iv. Please provide the 2021 depreciation expense (\$) that would have been reflected in revenue requirement in the scenario that the CIS and GIS assets had been applied the correct 10% depreciation rate instead.
 - v. Please confirm that between 2022-2025 these CIS and GIS assets have been depreciated at a rate of 10% (instead of the 20% reflected in rates).
 - vi. Please provide the remaining 2026 net CIS and GIS asset values related to the CIS and GIS assets that were funded in 2021 rates.

Response:

- a) Please refer to BHI's response to Staff-100 a) and b).

b)

- i. BHI provides the 2021 average rate base for each of the CIS and GIS assets separately of \$2,055,288 and \$707,030 respectively in Table 1 below.

Table 1 – Based on 2021 Cost of Service

Description	2021 Opening Net Fixed Assets	2021 Gross Assets	2021 Accumulated Depn	Closing Net Fixed Assets	2021 Rate Base	2021 Depreciation Expense at 5 years (20%)	2021 Depreciation Expense at 10 years (10%)
Calculation	a	b	c	d=b-c	e=(a+d)/2	f	g
Reference	n/a	n/a	n/a	n/a	SC-CCC-1 b) i)	SC-CCC-1 b) iii)	SC-CCC-1 b) iv)
CIS	\$2,177,602	\$2,685,428	\$752,454	\$1,932,974	\$2,055,288	\$510,499	\$255,249
GIS	\$759,971	\$914,413	\$260,324	\$654,089	\$707,030	\$175,883	\$87,941
Total	\$2,937,573	\$3,599,841	\$1,012,778	\$2,587,063	\$2,762,318	\$686,382	\$343,190

- ii. BHI confirms that the 2021 average rate base (part (i)) was funded in 2021 rates based on a 20% depreciation rate.
- iii. Please refer to Table 1 above (2021 depreciation expense reflected in revenue requirement was \$686,382).
- iv. Please refer to Table 1 above (2021 depreciation expense reflected in revenue requirement would have been \$343,190 had the correct 10% depreciation rate been applied).
- v. BHI confirms that between 2022-2025 these CIS and GIS assets have been depreciated at a rate of 10% (instead of the 20% reflected in rates).
- vi. The remaining 2026 net CIS and GIS asset values related to the CIS and GIS assets that were funded in 2021 rates (2021 opening and 2021 additions only) are \$810,743 and \$273,229 respectively based on 2021 Cost of Service asset values.

SC-CCC-2

2-Intervenor-50(n) and Exhibit 2, DSP, p. 117

- a) For the 2021-2025 period, please provide the planned budget associated with underground cable replacement and the actual costs associated with this activity.
- b) Please explain how this statement: “higher “per unit” costs on underground cable replacements due to installation of new cable in conduits (existing cable was directly buried) to bring the installation up to current standards and make future repairs more cost effective” explains the cost variance experienced with respect to this program. As part of the response, please confirm that the planned budget was based on installing new cable in conduits.

Response:

- a) BHI provides the planned budget associated with underground cable replacement and the actual costs for the period 2021-2025 in Table 1 below.

Table 1

Underground Cable Replacement	Budget	Actual
2021	\$400,000	\$815,152
2022	\$500,000	\$999,997
2023	\$500,000	\$1,974,672
2024	\$500,000	\$1,281,919
2025	\$500,000	\$793,667

- b) BHI confirms the planned budget was based on installing new cable in either existing conduits or new conduits. The budget assumed a portion of the cable being replaced would be directly buried and a portion would already be in conduit. A higher than expected proportion of the cable replaced in 2023 and 2024 was directly buried, which resulted in the increased unit cost as BHI was required to install conduit in addition to replacing the cable for these assets. This contributed to the overall cost variance for this program.

SC-CCC-3

2-Intervenor-57(a)

- a) Please explain the need to both replace and reverify, what appears to be, the same meters in given year (i.e., in each year BHI is both replacing and reverifying the same number of smart meters).

Response:

- a) There is not a need to both replace and reverify the same meters in a given year. BHI included the meters to be replaced in the reverification row in error in Table 1 in 2-Intervenor-57a). BHI provides an update to Table 1 in 2-Intervenor-57a) below to show the number of meters it is intending to reverify vs. replace.

Table 1

	2021	2022	2023	2024 Actual	2025 Bridge Year	2026 Test Year	2027	2028	2029	2030
Smart Meter Replacement/Reverification	\$0	\$226,356	\$402,556	\$406,000	\$277,442	\$2,600,245	\$2,547,332	\$2,597,833	\$774,996	\$747,701
Smart Meter Replacement (\$)	N/A	N/A	N/A	N/A	N/A	\$2,600,245	\$2,547,332	\$2,597,833	\$774,996	\$747,701
Smart Meter Replacement (Units)	N/A	N/A	N/A	N/A	N/A	13,668	13,668	13,668	2,233	1,655
Smart Meter Replacement (\$/Unit)	N/A	N/A	N/A	N/A	N/A	\$190	\$186	\$190	\$347	\$452
Smart Meter Reverification (\$)	\$0	\$226,356	\$402,556	\$406,000	\$277,442	\$0	\$0	\$0	\$0	\$0
Smart Meter Reverification (Units)	0	2,450	6,710	7,656	4,738	0	0	0	0	0
Smart Meter Reverification (\$/Units)	N/A	\$92	\$60	\$53	\$59	N/A	N/A	N/A	N/A	N/A

SC-CCC-4

2-Intervenor-59(a)

- a) To the extent that they are available, please provide the detailed economic evaluations for each of the three MTSA projects.

Response:

- a) BHI provides the detailed economic evaluation for the MTSA projects as CQ_Attachment_SC-CCC-4.

SC-CCC-5**4-Intervenor-93(c)**

- a) Please explain why bad debt expense is forecast in both the Accounting program (\$50k) and the Customer Service program (\$150k).

Response:

- a) Bad debt expense in the Accounting program relates to Miscellaneous Accounts Receivable (e.g. capital contributions, pole attachment revenue, isolations, accidents) and bad debt expense in the Customer Service program relates to A/R associated with customers' electricity and water bills.

SC-CCC-6

2-Intervenor-71

- a) Please explain why BHI would not make an insurance claim related to emergency repairs resulting from storm damage.

Response:

- a) BHI's insurance policy only covers property damage within 1000 ft of any of its premises (head office and substations), and therefore it is unable to make an insurance claim related to emergency repairs for distribution assets outside of this area. This restriction/exclusion is standard across the industry.

SC-CCC-7**2-Staff-23(d) and (g)**

- a) Please advise whether the unit numbers in Row 3 align with the unit designation set out in Table 2. For example, Unit T35 (Table 2) is the same truck as #35 with a score of 30 in 2-Staff-23(d).

Response:

- a) BHI confirms the unit numbers in Row 3 of IR_Attachment_2-Staff-23d_BHI_07242025 align with the unit designation set out in Table 2 of BHI's response to 2-Staff-23 g).

SC-CCC-8

Updated IRR – Appendix 2-JC and 4-Intervenor-93(c)

- a) Please explain the difference between the 2025 values provided in Updated IRR Appendix 2-JC and the 2025 values provided in 4-Intervenor-93(c).
- b) Please confirm that the correct sub-programs within the Stations Program are shown below.

Description
Salaries and Benefits
Materials - Station Mtoe/Ops
Building Operations and Maintenance
Insurance
Telephone/Utilities
Leases/Rent
Oil Tests
Software Maintenance
Station Mtoe/Ops - All Other
Total

Response:

- a) BHI provides the difference between the 2025 values provided in Updated IRR Appendix 2-JC and the 2025 values provided in 4-Intervenor-93(c) in Table 1 below.

BHI's response to 4-Intervenor-93 (c) represents its latest forecast of 2025 OM&A results based on known and/or material changes. It includes adjustments to Salaries and Benefits, the effect of which BHI did not have time to flow through and verify all of the OEB Appendices in the time allotted to respond to interrogatories (e.g. Appendix 2-D). In addition, it includes two costs associated with a cyber breach and legal work, which are one-time costs not expected to recur in 2026. Therefore these three amounts were excluded from the Updated IRR Appendix 2-JC.



Table 1

Description	2025 Bridge Year	Comments
Total OM&A - 2-JC - As Filed - Apr 16/2025	\$26,759,971	
Locates	\$45,196	Cost increase persists into 2026
OEB Costs	\$13,745	Cost increase persists into 2026
Total OM&A - 2-JC - IRRs - Jul 24/2025	\$26,818,912	
Salaries and Benefits	-\$34,874	2025 impact - will not persist into 2026
Cyber Breach Costs	\$113,076	2025 impact - will not persist into 2026
Legal Costs	\$50,000	2025 impact - will not persist into 2026
Total OM&A - 4-Intervenor-93c)	\$26,947,114	

- b) BHI confirms that the correct sub-programs within the Stations Program are shown in Table 2 below.

Table 2

Description
Salaries and Benefits
Materials - Station Mtce/Ops
Building Operations and Maintenance
Insurance
Telephone/Utilities
Leases/Rent
Oil Tests
Software Maintenance
Station Mtce/Ops - All Other
Total

SC-CCC-9**4-Intervenor-121(b)**

- a) Please further discuss BESI's use of the head office building (e.g., how many staff work out of that location, does BESI require storage space, etc.).

Response:

- a) Both of BESI's staff members — the General Manager and the Executive Assistant — work out of the head office building. They each have dedicated office space.

While most of their records are stored electronically, some hard copy documents are kept on office shelves. BESI also temporarily stores its EV charging stations in the building's storage area until they are installed at their intended locations.

The staff rarely use the office meeting rooms, as they primarily hold meetings via Microsoft Teams and offsite. They use the building's parking facilities for their personal vehicles.

SEC-CQ-1

Reference: [IRR Attachment_OEB_ACM_ICM_Model_BHI_07242025]

Question(s):

Please complete tab 10 of the ACM Model.

Response:

BHI provides the updated ACM model with the completed Tab 10 as Attachment_OEB_ACM_ICM_Model_BHI_08112025.

SEC-CQ-2

Reference: [IRR Attachment_OEB_ACM_ICM_Model_BHI_07242025]

Question(s):

Please provide estimated 2027 bill impacts, by rate class, for the proposed ACM.

Response:

BHI provides the estimated 2027 monthly bill impacts, by rate class, for the proposed ACM project in Table 1 below. The bill impacts are based on the rate riders calculated in Tab “11. Rate Rider Calc.” of the updated ACM model filed in response to SEC-CQ-1.

Table 1

Rate Class	Unit	# Units	ACM bill impact excluding HST
RESIDENTIAL	kWh	750	\$0.03
GENERAL SERVICE LESS THAN 50 kW	kWh	1,500	\$0.02
GENERAL SERVICE 50 TO 4,999 kW	kW	200	\$0.72
STREET LIGHTING	kW	0.22	\$0.00
UNMETERED SCATTERED LOAD	kWh	2,000	\$0.01

SEC-CQ-3**Reference: 2-Intervenor-13 (d)****Question(s):**

- a) Please confirm that the calculated Revenue Requirement does not include the increased depreciation expense (line n).
- b) Should SEC understand the response to be that in 2026 BHI received \$1,139,889 less in capital contributions as a result of the referenced amendments to the DSC?
- c) Is there any impact related to the application of the amendments in 2025 that impact the 2026 revenue requirements? If so, please provide details including the impact on the 2026 revenue requirement.

Response:

- a) The calculated revenue requirement excluded the increased depreciation expense (line n) in error. BHI provides the corrected estimate of the revenue requirement impact in 2026 resulting from the changes to connection and revenue horizon rules in Table 1 below.

Table 1

Description	Capital Structure	Calculation	% Rate (as Filed)	Calculation
Deemed STD	4.0%	a	3.91%	e
Deemed LTD	56.0%	b	4.36%	f
Deemed Debt	60.0%	c = a+b	4.33%	g = (a*e/c)+(b*f/c)
Deemed Equity	40.0%	d	9.00%	h
PILS			26.50%	i

Description	\$	Calculation
Fixed Assets Opening Balance 2026	\$0	j
Capital Expenditures	\$1,130,889	k
Work-in-Progress (example)	0	l
In-Service Additions	\$1,130,889	m = k + l
Straight Line Depreciation at 2.5% at 1/2 year	(14,136)	n = .025*m/2
Fixed Assets Closing Balance 2026	\$1,116,753	o = m+n
Average Fixed Assets	\$558,376	p = (j+o)/2
Rate Base	\$558,376	q = p
Deemed Interest	\$14,520	r = q*c*g
Deemed Equity	\$20,102	s = q*d*h
PILS	\$7,247	t = y
Revenue Requirement	\$56,005	u = r+s+t-n

Description	\$	Calculation
Deemed Equity	\$20,102	v = s
Tax Rate	26.50%	w = i
PILS before Gross Up	\$5,327	x = v*w
Gross Up PILS	\$7,247	y = x/(1-w)

- b) Yes, BHI expects to receive \$1,130,889 less in 2026 capital contributions as a result of the referenced amendments to the DSC.
- c) No, there are no impacts related to the application of the amendments in the 2025 Bridge Year that impact the 2026 Test Year revenue requirements.

SEC-CQ-4**Reference: 2-Intervenor-52**

Question(s):

In EB-2024-0010, the OEB made certain reductions to the requested ICM amounts for the Dundas St. Road Widening project. Please explain how the OEB's findings have been incorporated into the amounts BHI is seeking to add to rate base for the project.

Response:

In accordance with the OEB's Decision and Order¹, BHI reduced its requested ICM funding (which was capped at the Maximum Eligible Incremental Capital amount) for the purposes of its 2025 ICM rate rider as shown in Table 1 below.

Table 1

Description	2025
Capital Forecast	\$16,891,993
Less: Materiality Threshold	\$11,771,200
Maximum Eligible Incremental Capital	\$ 5,120,792
Replacing Assets in Poor Condition	\$ (197,757)
Higher Unit Costs vs. Waterdown Rd Project	\$ (160,692)
Approved ICM Funding per Decision and Order	\$ 4,762,343

BHI did not make the reductions identified in Table 1 to the amounts it is seeking to add to rate base for this project.

¹ EB-2024-0010, Decision and Order, December 17, 2024

SEC-CQ-5

Reference: 5-Staff-70

Question(s):

Please provide the source and copy of the referenced debt rate quote.

Response:

The debt rate quote was from TD Bank and is provided In Table 1 below. The quote of 4.60% is a fixed rate for 10 years and based on a 10 year amortization.

Table 1

As of July 8, 2025	Interest Rate Type	Rate Term						Drawdown Terms/ Drawdown Availability
Capex Term Loan \$15,000,000 CAD	Fixed Rate (% p.a.) based on 10 yr. amortization	1 yr.	2 yr.	3 yr.	5 yr.	7 yr.	10 yr.	Facility is subject to a maximum of 3 draws and \$10,000,000 per annum.
	Variable (via CORRA*)	3.90	3.90	4.10	4.30	4.50	4.60	The minimum amount of a drawdown by way of Term CORRA Loan and Daily Compounded CORRA Loan is CAD\$1,000,000. BHI shall advise the Bank of the requested contract maturity date or interest period for Term CORRA Loans and for Daily Compounded CORRA Loans under a committed facility. BHI shall provide the Bank with three (3) Business Days' notice of a requested Term CORRA Loan and Daily Compounded CORRA Loan.

VECC-CQ-1**Reference:****1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025****Question(s):**

- a) With respect to the Customer Count Tab, please explain the basis for the January 2026 forecast customer count for each rate class.

Response:

- a) The 2026 customer count forecast for each class is calculated as the geometric mean growth rate from 2015 to 2024 (2017 to 2024 for the Street Lighting and USL rate classes) applied to the forecast 2025 customer count of each class. The 2025 customer count forecast is an average of 2025 monthly customer counts, which includes actual January to May 2025 customer counts and forecast June to December customer counts. June 2025 customer counts are forecast based on the monthly average geometric growth rate applied to actual May 2025 customer counts and the remaining customer counts are forecast based on the monthly average geometric growth rate applied to the forecast count from the preceding month.

VECC-CQ-2

Reference:

1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025

Question(s):

- a) With respect to the actual 2024 monthly usage reported in the Monthly Data Tab for all classes except Street Lighting, please explain why the values in the updated Load Forecast differ from those reported in the Load Forecast Model filed with the Application.

Response:

- a) Actual 2024 monthly volumes were corrected in the updated Load Forecast and now align with the RRRs and the RTSR model.

VECC-CQ-3**Reference:****1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025****Question(s):**

- a) With respect to the Res Predicted Monthly Tab, the values for OEA_GDP are sourced from the Monthly Data Tab which, in turn, sources the values from the Economic Tab. However, it appears that in sourcing the OEA_GDP values from the Economic Tab the formulae used in the Monthly Data Tab reference the wrong year (e.g., values for 2023 in the Economic Tab are used as values for 2024 in the Monthly Data Tab). Please confirm whether this is the case.
- b) If confirmed, does the fact that the Monthly Data Tab and the Res Predicted Monthly Tab use the incorrect historic OEA_GDP values for January 2015-May 2025 mean that the Residential regression model was estimated using incorrect data?
 - i. If not, why not?
 - ii. If yes, please provide an updated Load Forecast using the correct data to estimate the Residential model.
- c) Please review the data used in the estimation of the regression models for the other classes and confirm that, in each case, the correct data values were used.

Response:

- a) BHI confirms the formulae used in the Monthly Data Tab referenced the wrong year in sourcing the OEA_GDP values from the Economic Tab.
- b) Yes, the residential regression model was estimated using incorrect data, specifically that the Monthly Data Tab and the Res Predicted Monthly Tab use the incorrect historic OEA_GDP values for January 2015-May 2025.
 - i. See above response.
 - ii. An updated load forecast is provided as Attachment_Load_Forecast_Model_BHI_08112025. The 2026 Residential kWh forecast in this model is 527,179,883 kWh. The OEA GDP variable is not statistically significant with this correction so it has been removed. For reference, the model with the corrected figures that maintains the OEA GDP variable is 536,921,797 kWh.
- c) BHI reviewed the data used for the regressions and predicted volumes for the General Service < 50 kW and General Service > 50 kW classes and the correct data values were used.

VECC-CQ-4**Reference:****3-Intervenor-84 a) and c)****Question(s):**

- a) Do the 2026 forecast of 578,681,571 kWh (per 84 a)) and the 2026 forecast of 543,620,703 kWh (per 84 c)) both represent a No-CDM forecast similar to the 583,399,477 kWh value from the initial Application and, if not, what do they represent?

Response:

- a) No, the 578,681,571 and 543,620,703 kWh figures are the final forecast volumes after persisting CDM is removed, additional loads are added, and the forecast CDM adjustment is applied. The No-CDM forecast figure corresponding to part a) is 607,632,355 kWh and the No-CDM forecast figure corresponding to part c) is 572,571,487.

VECC-CQ-5**Reference:****3-Intervenor 85 b) and 86 b)****Question(s):**

- a) The GS>50 2026 forecast reported in 86 b) for the model with a COVID variable (177,886,088 kWh) is the same as that reported in 85 b) for the GS<50 class. Please review and correct the forecast values as required.

Response:

- a) BHI's response to 3-Intervenor 86 b) was incorrect and referenced the GS<50kW values in error. It should have stated "The statistical results for the three scenarios are provided below. The forecast for the scenario with the highest COVID variable statistical significance is scenario 3, which produces a forecast of 768,252,481 kWh in 2025 and 749,173,002 kWh in 2026".

VECC-CQ-6**Reference:****3-Intervenor 86 c), 1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025, Total Additional-Lost Loads Tab****Question(s):**

- a) Please explain why the adjustment to the GS>50 2026 load forecast for the “lost customer” uses 2023 usage as the base when the updated load forecast uses actual data up to May 2025, which includes months where the customer was reclassified to the GS<50 class and includes a month after the closure date for the customer.

Response:

- a) The comment on reclassification to the GS<50 kW class in 3-Intervenor-86c) was a general comment on customers that are reclassified from GS>50 kW to GS<50 kW, and not necessarily ceasing operations. The “lost customer” was not reclassified to the GS<50 kW class.

When BHI updated its load forecast for actuals up to 2025 May YTD it inadvertently did not update the calculations for the “Lost Customer” to incorporate actual data up to May 2025 instead of 2023 usage. 2024 and 2025 actual demand was 13,081 kW as compared to in the “Total Additional-Lost Loads” tab of 17,900 kW in the Load Forecast model. The customer’s demands in 2023 remain a better reflection of the billed loads that are lost when the customer ceased operations.

The adjustment for lost load was made to the GS>50 kW forecast that uses 125 months of data. The “Lost Customer” load was not included in only one of these months (May 2025) and as such the absence of this load in May 2025 does not materially impact the Test Year forecast.

VECC-CQ-7

Reference:

7-Intervenor-132, Attachment 11_Load_Profile_Derivation_BHI_04162025

Question(s):

- a) With respect to New York utilities' TOU rates, what hours of the weekday are considered to be on-peak?

Response:

- a) Peak hours differ by utility. Con Edison's on-peak hours are from 8:00am to midnight and super-peak hours are 2:00pm to 6:00pm. Central Hudson's on-peak hours are from 2:00pm to 7:00pm. National Grid's on-peak hours are 5:00pm to 8:00pm in the winter months and 11:00am to 5:00pm in the summer months.

VECC-CQ-8**Reference:****7-Intervenor-133****Question(s):**

- a) Please explain the basis on which each of the four accounts included in the derivation of the Billing and Collecting weighting factors is allocated to the customer classes.

Response:

- a) The four accounts included in the derivation of the Billing and Collecting weighting factors are allocated to the customer classes as follows:
- Customer Billing (5315) – based on direct actual billing costs by rate class and indirect allocated costs (e.g. testing CIS changes required as a result of changes in regulations)
 - Collecting (5320) – based on each rate class's historical Bad Debt experience
 - Collection Charges (5330) – based on each rate class's historical Bad Debt experience
 - Misc Customer Accounts Expense (5340) – allocated to each rate class based on their proportionate share of the total costs for USoAs 5315, 5320 and 5330.

VECC-CQ-9**Reference:****1-Staff-1, Attachment_RRWF_BHI_07242025****Question(s):**

- a) With respect to the Cost Allocation Tab, please explain the material change in the Status Quo Revenue/Cost Ratio for the GS<50 class as between the application (108.48%) and the interrogatory responses (123.79%).

Response:

- a) The material change in the Status Quo Revenue/Cost Ratio for the GS<50 class from the Application to the interrogatory responses was driven by an error in the Service weighting factors in the application, which were based on gross cost instead of installed cost (paid by BHI). Please refer to 7-Staff-80 for further details.

VECC-CQ-10**Reference: 1-Staff-1, Attachment_Load_Forecast_Model_BHI_07242025, VECC-CQ-1**

Question(s):

With respect to the Customer Count Tab, please explain the basis for the different formula used for the January 2026 forecast customer count for each rate class.

Response:

The calculation of annual customer counts in rows 5 to 16 of the Customer Count tab is the basis for the forecast number of customers in 2026. The calculations in rows 24 to 59 provide monthly counts in case monthly forecast counts are required because the customer count variable is used in a class's regression model.

The formula for January 2026 is different in order to impute the correct starting point so the forecast average 2026 monthly customer count equals the 2026 annual customer count. The formula for January 2026 ensures that, for each rate class, the correct starting point is such that the monthly geometric growth rate applied to the January 2026 count, and each subsequent month, results in month customer counts that are, on average for the year, equal to the annual customer count forecast calculated in row 16.

VECC-CQ-11**Reference:**

CQ-Staff-106
2-Intervenor-34

Question(s):

- a) What is the relationship between a connection and the addition of a new customer?
- b) What is the relationship between a buyback from developers and connections?
- c) Provide # of connections in 2022 and 2023.

Response:

- a) In some cases, one new connection results in the addition of a new customer. However, there can be a new connection without a corresponding increase to the number of customers in the following situations:
 - Houses being torn down and rebuilt where a new meter gets installed;
 - Service upgrades that result in the meter having to be replaced;
 - Net metering installations where the meter has to be replaced.

Additionally, new customer connections are counted regardless of when they happen in the year, while the customer count is an average (e.g. a new connection at the beginning of July counts as 1 connection and 0.5 of a customer count). This inflates the number of connections compared with the number of new customers.

Lastly, the customer count includes decreases when customers disconnect.

- b) When a developer chooses the alternative bid option in the DSC for subdivision development, and transfers those assets to BHI at the transfer price, BHI refers to this as a buyback¹. The connections or units within the subdivision translate into a one-to-one addition of new customers in the month of the connection. This does not necessarily translate into one customer for a full year.
- c) BHI provides the # of connections in 2022 and 2023 in Table 1 below.

¹ DSC, Section 3.2.18



Table 1

New Connections	#
2022	316
2023	288
2024	457
2025	524
2026	612
2027	700
2028	1,253
2029	1,341

VECC-CQ-12**Reference: 3-Intervenor-84, 3-Intervenor-85, 3-Intervenor-86****Question(s):**

Please provide the results (i.e., regression equation, regression statistics and 2026 forecast) where the model also includes the following:

- i) Residential customer count as an explanatory variable (per BHI's response to 3-Intervenor-84 a);
- ii) COVID-related variable as an explanatory variable for the Residential class model (per BHI's response to 3-Intervenor-84 c), Scenario 3);
- iii) COVID-related variable as an explanatory variable for the GS<50 class model (per BHI's response to 3-Intervenor-85 b), Scenario 3);
- iv) COVID-related variable as an explanatory variable for the GS>50 class model (per BHI's response to 3-Intervenor-86 b), Scenario 3);

Response:

BHI provides a load forecast with the above explanatory variables included as Attachment_VECC-CQ-12_Load_Forecast_Model_BHI_08112025. The 2026 forecast kWh volumes for this scenario are provided in Table 1 below.

Table 1

2026	kWh
Residential	543,759,271
GS < 50 kW	171,402,772
GS > 50 kW	747,394,113

The regression equation and statistics are provided in Tables 2, 3 and 4 below. The Residential regression excludes the OEA_GDP variable because that variable is not statistically significant with the customer count and COVID variables.

Table 2

Model 2: Prais-Winsten, using observations 2015:01-2025:05 (T = 125)				
Dependent variable: Res_NoCDM				
rho = 0.127885				
	coefficient	std. error	t-ratio	p-value
const	(77,106,558)	12,916,821	(5.97)	0.0000
HDD14	14,902	1,500	9.93	0.0000
CDD14	80,873	3,309	24.44	0.0000
Shoulder	(2,711,626)	407,363	(6.66)	0.0000
MonthDays	1,533,633	161,227	9.51	0.0000
Residential Customers	1,121	195	5.75	0.0000
COVID3HDDInt84	6,408	1,977	3.24	0.0016
COVID3CDDInt84	17,046	3,391	5.03	0.0000
Statistics based on the rho-differenced data				
Sum squared resid	2.72E+14	S.E. of regression		1,523,619
R-squared	0.9642	Adjusted R-squared		0.9621
F(7, 117)	387.07	P-value(F)		9.42E-78
rho	-0.0238	Durbin-Watson		1.9209
Statistics based on the original data				
Mean dependent var	46,402,777	S.D. dependent var		7,824,598

Table 3

Model 2: Prais-Winsten, using observations 2015:01-2025:05 (T = 125)				
Dependent variable: GS It 50 NoCDM				
rho = 0.389371				
	coefficient	std. error	t-ratio	p-value
const	(10,013,973)	1,855,098	(5.40)	0.0000
HDD14	5,082	330	15.40	0.0000
CDD14	12,142	685	17.73	0.0000
OEA_GDPChange	4	2	1.90	0.0601
GS It 50 Customers	2,269	293	7.75	0.0000
Shoulder	(156,935)	84,812	(1.85)	0.0668
MonthDays	350,950	30,654	11.45	0.0000
COVID3Int85_86	(2,084,853)	214,022	(9.74)	0.0000
Statistics based on the rho-differenced data				
Sum squared resid	1.30E+13	S.E. of regression		333,948
R-squared	0.9215	Adjusted R-squared		0.9168
F(7, 117)	182.27	P-value(F)		8.03E-60
rho	-0.0273	Durbin-Watson		1.7898
Statistics based on the original data				
Mean dependent var	14,767,664	S.D. dependent var		1,155,160

Table 4

Model 3: Prais-Winsten, using observations 2015:01-2025:05 (T = 125)				
Dependent variable: GS_gt_50_NoCDM				
rho = 0.482605				
	coefficient	std. error	t-ratio	p-value
const	13,642,994	3,513,207	3.88	0.0002
HDD10	17,703	1,299	13.63	0.0000
CDD14	46,258	1,935	23.90	0.0000
Trend	(58,060)	6,514	(8.91)	0.0000
Dec	(2,274,410)	393,826	(5.78)	0.0000
MonthDays	1,886,530	114,171	16.52	0.0000
Tor_FTEAdjChange	5,396	1,743	3.10	0.0025
COVID3Int85_86	(5,745,197)	974,743	(5.89)	0.0000
Statistics based on the rho-differenced data				
Sum squared resid	2.11E+14	S.E. of regression		1,341,483
R-squared	0.9381	Adjusted R-squared		0.9344
F(7, 117)	243.84	P-value(F)		1.20E-66
rho	-0.0857	Durbin-Watson		2.1632
Statistics based on the original data				
Mean dependent var	72,584,501	S.D. dependent var		5,236,218