Ontario Energy Board | Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2024-0010

BURLINGTON HYDRO INC.

Application for rates and other charges to be effective January 1, 2025

BEFORE: **Patrick Moran**
Presiding Commissioner

Pankaj Sardana
Commissioner

December 17, 2024

1. OVERVIEW

The Ontario Energy Board (OEB) is approving changes to the rates that Burlington Hydro Inc. (Burlington Hydro) charges to distribute electricity to its customers, effective January 1, 2025.

As a result of this Decision and Order, there will be a monthly total bill increase of $0.47 for a residential customer with a monthly consumption of 750 kWh. This change does not factor in applicable taxes, the Ontario Energy Rebate, or the Incremental Capital Module (ICM) funding.

In this Decision and Order, the OEB approves:

1. The annual adjustment to distribution rates using the OEB-approved Price Cap IR formula.
2. The updated RTSRs calculated using the OEB-approved methodology.
3. The disposition of the $2,179,551 balance in its Group 1 Deferral and Variance Accounts on an interim basis as at December 31, 2023, including interest projected to December 31, 2024.
4. 2025 LRAM-eligible amounts to be recorded in Account 1595 for disposition in a future-rate setting proceeding.
5. ICM funding of $4,762,343 and the associated incremental revenue requirement to be calculated by Burlington Hydro. The associated revenue requirement will be offset by the 2023 balance including carrying charges up to Q4 2024 in the variance Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account.

2. CONTEXT AND PROCESS

Burlington Hydro filed its application on August 15, 2024, under section 78 of the *Ontario Energy Board Act, 1998* and in accordance with Chapter 3 (Incentive Rate-Setting Applications) of the OEB's *Filing Requirements for Electricity Distribution Rate Applications* (Filing Requirements). The application was based on the Price Cap Incentive Rate-setting (Price Cap IR) option, with a five-year term.

The Price Cap IR option is one of three incentive rate-setting mechanisms (IRM) used by the OEB.[1] It involves the setting of rates through a cost of service application in the first year and mechanistic price cap adjustments which may be approved through IRM applications in each of the ensuing adjustment years.

The OEB follows a standardized and streamlined process for processing IRM applications filed under Price Cap IR. In each adjustment year of a Price Cap IR term, the OEB prepares a Rate Generator Model that includes, as a placeholder, information from the distributor's past proceedings and annual reporting requirements. A distributor then reviews, completes, and includes the model with its application, and may update the model during the proceeding to make any necessary corrections or to incorporate new rate-setting parameters as they become available.

Burlington Hydro serves approximately 69,000 mostly residential and commercial electricity customers in the City of Burlington.

Notice of the application was issued on September 3, 2024. Vulnerable Energy Consumers Coalition (VECC) requested intervenor status and cost eligibility. The OEB approved VECC as an intervenor and for cost eligibility.

The application was supported by pre-filed written evidence and a completed Rate Generator Model and, as required during the proceeding, Burlington Hydro updated and clarified the evidence.

Burlington Hydro responded to interrogatories from OEB staff and VECC. Final submissions on the application were filed by OEB staff, VECC, and Burlington Hydro.

[1] Each of these options is explained in the OEB's *Handbook for Utility Rate Applications*.

3. DECISION OUTLINE

Each of the following issues is addressed in this Decision and Order, together with the OEB's findings.

- Annual Adjustment Mechanism
- Retail Transmission Service Rates
- Group 1 Deferral and Variance Accounts
- Lost Revenue Adjustment Mechanism Variance Account
- Incremental Capital Module

Instructions for implementing Burlington Hydro's new rates and charges are set out in the final section of this Decision and Order.

This Decision and Order does not address rates and charges approved by the OEB in prior proceedings, such as specific service charges[2] and loss factors, which are out of the scope of an IRM proceeding and for which no further approvals are required to continue to include them on the distributor's Tariff of Rates and Charges.

[2] Certain service charges are subject to annual inflationary adjustments to be determined by the OEB through a generic order. For example, the OEB's Decision and Order in EB-2024-0226, September 26, 2024, established the adjustment for energy retailer service charges, effective January 1, 2025; and the OEB's Decision and Order in EB-2024-0227, issued September 26, 2024, established the 2025 Wireline Pole Attachment Charge, effective January 1, 2025.

4. ANNUAL ADJUSTMENT MECHANISM

Burlington Hydro has applied to change its rates, effective January 1, 2025. The proposed rate change is based on a mechanistic rate adjustment using the OEB-approved **inflation minus X-factor** formula applicable to IRM applications. The adjustment applies to distribution rates (fixed and variable) uniformly across all customer classes.[3]

The components of the Price Cap adjustment formula applicable to Burlington Hydro are set out in the table below. Inserting these components into the formula results in a 3.45% increase to Burlington Hydro's rates: **3.45% = 3.60% - (0.00% + 0.15%)**.

Table 4.1: Price Cap IR Adjustment Formula

Components		Amount
Inflation factor[4]		3.60%
Less: X-factor	Productivity factor[5]	0.00%
	Stretch factor (0.00% to 0.60%)[6]	0.15%

An inflation factor of 3.60% applies to all IRM applications for the 2025 rate year. The X-factor is the sum of the productivity factor and the stretch factor. It is a productivity offset that varies among different groupings of distributors. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors with a tangible incentive to improve efficiency or else experience declining net income. The productivity component of the X-factor is based on industry conditions over a historical study period and applies to all IRM applications for the 2025 rate year. The stretch factor component of the X-factor is one of five stretch factor groupings established by the OEB, ranging from 0.00% to 0.60%. The stretch factor assigned to any distributor is based on the distributor's total cost performance as benchmarked

[3] The adjustment does not apply to the following components of delivery rates: rate riders, rate adders, low voltage service charges, retail transmission service rates, wholesale market service rate, smart metering entity charge, rural or remote electricity rate protection charge, standard supply service – administrative charge, transformation and primary metering allowances, loss factors, specific service charges (other than the Wireline Pole Attachment charge), and microFIT charge.

[4] OEB Letter, 2025 Inflation Parameters, issued June 20, 2024

[5] Report of the Ontario Energy Board – "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" EB-2010-0379, December 4, 2013

[6] Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2023 Benchmarking Update", prepared by Pacific Economics Group LLC., August 6, 2024

against other distributors in Ontario. The stretch factor assigned to Burlington Hydro is 0.15%, resulting in a rate adjustment of 3.45%.

No parties made submissions on this matter.

Findings

Burlington Hydro's request for a 3.45% rate increase is in accordance with the annually updated parameters set by the OEB. The adjustment is approved, and Burlington Hydro's new rates shall be effective January 1, 2025.

5. RETAIL TRANSMISSION SERVICE RATES

In Ontario, some distributors are connected directly to a licensed transmitter, while others may be embedded, or partially-embedded, within the distribution system of another licensed distributor. Burlington Hydro is transmission connected.

On November 1, 2024, the OEB announced preliminary Uniform Transmission Rates (UTRs) effective January 1, 2025.[7] To recover its cost of transmission services, Burlington Hydro requested approval to adjust the Retail Transmission Service Rates (RTSRs) that it charges its customers in accordance with the preliminary UTRs. Burlington Hydro updated its RTSRs based on the preliminary UTRs.

The OEB sets the UTRs based on the approved revenue requirements for multiple transmitters. Preliminary UTRs are based on those revenue requirements that have already been approved for 2025. These preliminary UTRs are to be used for the setting of RTSRs to minimize the accumulation of variances in Retail Settlement Variance Accounts 1584 (Retail Transmission Network Charge) and 1586 (Retail Transmission Connection Charge). The cost consequences of any future adjustments to 2025 UTRs to reflect remaining approvals to a transmitter's revenue requirement will be tracked in these variance accounts and recovered over time.

No parties made submissions on this matter.

Findings

Burlington Hydro's proposed adjustment to its RTSRs is approved.

The RTSRs have been adjusted based on the preliminary UTRs.[8]

If final UTRs differ from the preliminary UTRs, the resulting differences will be captured in Retail Settlement Variance Accounts 1584 (Retail Transmission Network Charge) and 1586 (Retail Transmission Connection Charge).

[7] EB-2024-0244, OEB Letter "2025 Preliminary Uniform Transmission Rates and Hydro One Sub-Transmission Rates", issued November 1, 2024
[8] Ibid.

6. GROUP 1 DEFERRAL AND VARIANCE ACCOUNTS

In each year of an IRM term, the OEB will review a distributor's Group 1 deferral and variance accounts (DVAs) to determine whether those balances should be disposed. OEB policy states that Group 1 account balances should be disposed if they exceed, on a net basis (as a debit or credit), a pre-set disposition threshold of $0.001 per kWh, unless a distributor can justify why balances should not be disposed.[9] If the net balance does not exceed the threshold, a distributor may still request disposition.[10]

The 2023 year-end net balance for Burlington Hydro's Group 1 accounts eligible for disposition, including interest projected to December 31, 2024, is a debit of $2,179,551, and pertains to variances accumulated during the 2022 to 2023 calendar years. The disposition request includes a deferred disposition for balances in Accounts 1588 RSVA Power and 1589 RSVA Global Adjustment from the 2024 IRM application.[11] The $2,179,551 disposition amount represents a total claim of $0.0015 per kWh, which exceeds the disposition threshold.

Burlington Hydro has requested disposition of this amount over a one-year period.

Included in the Group 1 accounts are certain variances related to costs that are paid for by a distributor's customers on different bases, depending on their classification. "Class A" customers, who participate in the Industrial Conservation Initiative, pay for Global Adjustment (GA) charges based on their contribution to the five highest Ontario demand peaks over a 12-month period. "Class B" customers pay for GA charges based on their monthly consumption, either as a standalone charge or embedded in the Regulated Price Plan (RPP).[12] A similar mechanism applies to Class A and Class B customers for Capacity Based Recovery (CBR) charges.[13] The balance in the GA variance account is attributable to non-RPP Class B customers and is disposed through a separate rate rider. The balance in the CBR Class B variance account is attributable to all Class B customers.

Burlington Hydro had one or more Class A customers during the period in which variances accumulated so it has applied to have the balance of the CBR Class B

[9] Report of the OEB – "Electricity Distributors' Deferral and Variance Account Review Initiative" (EDDVAR), EB-2008-0046, July 31, 2009
[10] OEB letter, "Update to the Electricity Distributors' Deferral and Variance Account Review ("EDDVAR Report"), released July 2009 (EB-2008-0046)", issued July 25, 2014
[11] EB-2023-0008
[12] For additional details on the Global Adjustment charge, refer to the Independent Electricity System Operator (IESO)'s website.
[13] All Class B customers (RPP and non-RPP) pay the CBR as a separate charge based on their monthly consumption. For additional details on the CBR for Class A customers, refer to the IESO's website.

variance account disposed through a separate rate rider for Class B customers to ensure proper allocation between Class A and Class B customers.

During the period in which variances accumulated, Burlington Hydro had one or more customers transition between Class A and Class B. Under the general principle of cost causality, customer groups that cause variances that are recorded in Group 1 accounts should be responsible for paying the debits (or receiving credits) for their disposal. Burlington Hydro has proposed to allocate a portion of the GA and CBR Class B balances to its transition customers, based on their customer-specific consumption levels.[14] The amounts allocated to each transition customer are proposed to be recovered by way of 12 equal monthly payments.

Burlington Hydro identified three variances between accounts found in Tab "3 Continuity Schedule" of the Rate Generator Model and the Reporting and Record-Keeping Requirements (RRR) data.[15] First, there is a $98,108 variance found in account 1580 (RSVA – Wholesale Market Service Charge). Burlington Hydro explained that this was not a difference between the continuity schedule and the RRR data, but that the Rate Generator Model was double counting the CBR Class B balance of $98,108 in the RSVA – Wholesale Market Service Charge in Column BV. Burlington Hydro also identified two other minor variances of $954 in Account 1595 (2019) and a credit of $438 in Account 1595 (2020) in the continuity schedule, both of which were due to carrying charge adjustments not previously reported in RRR data for 2023.

No parties made submissions on this matter.

Findings

The balances proposed for disposition do not fully reconcile with the amounts reported as part of the OEB's *Electricity Reporting and Record-Keeping Requirements*, but the OEB is satisfied with Burlington Hydro's explanation of the variances and commitment to request a RRR revision to correct these variances.

The OEB approves the disposition of a debit balance of $2,179,551 as of December 31, 2023, including interest projected to December 31, 2024, for Group 1 accounts on an interim basis.

Table 6.1 identifies the principal and interest amounts, which the OEB approves for disposition.

[14] 2025 IRM Rate Generator Model, Tab 6.1a "GA Allocation" and Tab 6.2a "CBR B_Allocation"
[15] Manager's Summary, Exhibit 1, Page 10-11.

Table 6.1: Group 1 Deferral and Variance Account Balances

Account Name and Number		Principal Balance ($) A	Interest Balance ($) B	Total Claim ($) C=A+B
Smart Metering Entity Charge Variance Account	1551	(127,250)	(9,371)	(136,621)
RSVA - Wholesale Market Service Charge	1580	(1,501,721)	(60,151)	(1,561,872)
Variance WMS - Sub-account CBR Class B	1580	247,959	7,169	255,128
RSVA - Retail Transmission Network Charge	1584	1,011,850	113,034	1,124,884
RSVA - Retail Transmission Connection Charge	1586	674,446	63,226	737,672
RSVA – Power	1588	1,125,833	(112,651)	1,013,181
RSVA - Global Adjustment	1589	579,362	80,699	660,061
Disposition and Recovery/ Refund of Regulatory Balances (2020)	1595	(519,391)	606,509	87,118
Total for Group 1 accounts		**1,491,088**	**688,464**	**2,179,551**

The balance of each of the Group 1 accounts approved for disposition shall be transferred to the applicable principal and interest carrying charge sub-accounts of Account 1595. Such transfer shall be pursuant to the requirements specified in the *Accounting Procedures Handbook for Electricity Distributors.*[16] The date of the transfer must be the same as the effective date for the associated rates, which is generally the start of the rate year.

The OEB approves these balances to be disposed through interim rate riders, charges, or payments, as calculated in the Rate Generator Model. The interim rate riders, charges, and payments, as applicable, will be in effect over a one-year period from January 1, 2025 to December 31, 2025.[17]

[16] Article 220, Account Descriptions, *Accounting Procedures Handbook for Electricity Distributors*, effective January 1, 2012
[17] 2025 IRM Rate Generator Model Tab 6.1 GA, Tab 6.1a GA Allocation, Tab 6.2 CBR B, Tab 6.2a CBR B_Allocation and Tab 7 Calculation of Def-Var RR

7. LOST REVENUE ADJUSTMENT MECHANISM VARIANCE ACCOUNT

The OEB has historically used a Lost Revenue Adjustment Mechanism (LRAM) Variance Account (LRAMVA) to capture impacts on a distributor's revenues arising from differences between actual and forecast Conservation and Demand Management (CDM) savings included in its last OEB-approved load forecast. The use of the LRAMVA is no longer the default approach for CDM activities. The OEB has recently issued guidelines to electricity distributors related to non-wires solutions.[18] In accordance with these guidelines, a distributor may request the use of an LRAMVA for distribution-rate funded non-wires solutions, and this may include traditional CDM activities or Local Initiatives Program activities, with need to be determined on a case-by-case basis.

Distributors delivered CDM programs to their customers through the Conservation First Framework (CFF) that began on January 1, 2015 until March 20, 2019, when the CFF was revoked.[19]

Distributors that do not have a confirmed zero balance in the LRAMVA are required to seek disposition as part of their IRM application, with supporting information, or provide a rationale for not doing so.[20]

Distributors are also eligible to make an LRAMVA request relating to persisting impacts of conservation programs until their next rebasing. The OEB previously provided direction for distributors to seek approval of LRAM-eligible amounts for 2023 onwards on a prospective basis, and a rate rider in the corresponding rate year, to address amounts that would otherwise be recorded in the LRAMVA for all years until their next rebasing application.

Burlington Hydro had LRAM-eligible amounts for future years approved on a prospective basis in a previous year. For the 2025 rate year, Burlington Hydro was approved for a prospective LRAM-eligible credit amount of $7,100 in 2023 dollars.[21] Prospective LRAM amounts are to be adjusted mechanistically by the approved inflation minus X-factor applicable to IRM applications in effect for a given year and recovered through a rate rider in the corresponding rate year.[22] Applying Burlington Hydro's

[18] *Non-Wires Solutions Guidelines for Electricity Distributors*, March 28, 2024
[19] On March 20, 2019 the Minister of Energy, Northern Development and Mines issued separate Directives to the OEB and the IESO.
[20] Chapter 3 Filing Requirements, section 3.2.7.1
[21] EB-2023-0008, Decision and Order, December 14, 2023
[22] Chapter 3 Filing Requirements, section 3.2.7.1

approved 2024 and 2025 inflation minus X-factor adjustments to the previously approved prospective balance for the 2025 rate year, results in a credit amount of $7,686.[23] Burlington Hydro notes that the resulting rate rider calculation for the GS<50kW rate class produces a volumetric rate rider that rounds to zero.[24] Consequently, Burlington Hydro has requested that the 2025 LRAM-eligible amount (in 2025 dollars) be recorded in Account 1595 for disposition in a future rate application. Burlington Hydro further notes that this request is consistent with the OEB's guidance on *Treatment of Negligible Rate Adders and Rate Riders* from the Chapter 3 Filing Requirements.[25]

No parties made submissions on this matter.

Findings

The OEB acknowledges that Burlington Hydro properly applied the 2024 and 2025 inflation minus X-factor adjustments to the previously approved prospective balance for the 2025 rate year (in 2023 dollars) to arrive at the 2025 LRAM-eligible amount (in 2025 dollars) of $(7,686). The OEB also acknowledges that the calculation for one of the rate riders to recover the 2025 LRAM-eligible amount (in 2025 dollars) produces a volumetric rate rider that rounds to zero at five significant digits. The OEB approves Burlington Hydro's request for the 2025 LRAM-eligible amount (in 2025 dollars) of $(7,686) to be recorded in Account 1595 for disposition in a future rate application. This treatment is consistent with the OEB's guidance on *Treatment of Negligible Rate Adders and Rate Riders* from Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications[26]. The OEB also confirms the previously approved LRAM-eligible amounts, which have been mechanistically adjusted to 2025 dollars by applying the approved inflation minus X-factors, as set out in Table 7.1 below.[27]

[23] Calculated as: (previously approved 2025 LRAM-eligible amount in 2023 dollars) x (2024 approved inflation minus X-factor) and then (previously approved 2025 LRAM-eligible amount in 2024 dollars) x (2025 approved inflation minus X-factor)
[24] Manager's Summary, p. 22
[25] Ibid.
[26] Chapter 3 Filing Requirements, Section 3.4 Appendix A
[27] EB-2023-0008, Decision and Order, December 14, 2023; amounts in 2023 dollars were first adjusted by the 2024 approved inflation minus X-factor, and then the 2025 approved inflation minus X-factor

Table 7.1: LRAM-Eligible Amounts for Prospective Disposition

Year	LRAM-Eligible Amount (in 2023 $)	LRAM-Eligible Amount (in 2024 $)[28]	LRAM-Eligible Amount (in 2025 $)[29]
2026	(7,167)	(7,500)	(7,759)
2027	(7,167)	(7,500)	(7,759)

[28] Calculated as: (previously approved 2025 LRAM-eligible amount in 2023 dollars) x (2024 approved inflation minus X-factor).
[29] Calculated as: (previously approved 2025 LRAM-eligible amount in 2024 dollars) x (2025 approved inflation minus X-factor).

8. INCREMENTAL CAPITAL MODULE

The OEB's incremental capital module (ICM) policy[30] was established to address the treatment of a distributor's capital investment needs that arise during a Price Cap IR rate-setting plan, and which needs are incremental to a calculated materiality threshold. To qualify for ICM funding, a distributor must satisfy the OEB's well-established eligibility criteria of materiality, need and prudence.[31]

There are three elements to the materiality criterion; the application must meet the materiality threshold; the distributor must demonstrate that the project is not a minor expenditure in comparison to its overall capital budget; and the incremental funding must have a significant influence on distributor's operations.

The need criterion requires a distributor to pass a "means" test. Furthermore, the requested amounts must be based on discrete projects, should be directly related to the claimed driver, and must be clearly outside of the base upon which the rates were derived.

For the prudence criterion, a distributor must establish that the incremental capital amount it proposes to incur is prudent.

The Half-Year Rule

For ICM-related capital additions, the ICM policy allows for a full-year's depreciation, capital cost allowance, and return on capital, for all years of a Price Cap IR plan, other than in the final year prior to rebasing.[32] However, in the final year prior to rebasing, the standard half-year rule is used for calculation of the depreciation and return on capital, and associated taxes or payments in lieu of taxes (PILs) are treated as if it was the first year that an asset enters service.[33]

[30] The OEB's policy for the funding of incremental capital is set out in the *Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014 (Funding of Capital Report) and the subsequent *Report of the OEB New Policy Options for the Funding of Capital Investments: Supplemental Report* (Supplemental Report) (collectively referred to as the ICM policy).
[31] Funding of Capital Report, p. 17.
[32] Supplemental Report pp. 7-11. When the half-year rule is applied, only half of the annual depreciation and CCA is allowed for depreciation and tax/PILs purposes. This ensures that the distributor recovers only a half-year of return on depreciation and capital as per the intent of the half-year rule.
[33] Funding of Capital Report, p. 23

The ICM Project

Burlington Hydro requested $5,120,792 in ICM funding for the mandatory relocation of electrical distribution assets required for road widening work on Dundas Street (from Guelph Line to Kerns Road and from Northampton Boulevard to Guelph Line). The relocation work was requested by the Regional Municipality of Halton (Halton Region), the road authority under the *Public Service Works on Highways Act* (PSWHA). The project is non-discretionary due to Burlington Hydro's statutory obligations under the PSWHA.

Burlington Hydro states that it must relocate approximately 164 poles (and associated hardware, cable, and wire) and 21 transformers. The project includes the installation of new poles, the transfer of conductors to the new poles, the removal of old poles in the overhead portion, and the relocation/installation of underground infrastructure.

The total cost of the project is $10,079,095. Burlington Hydro states that for road authority relocation requests, it follows the PSWHA and associated regulations and collects contributed capital of 50% of the labour and labour-saving equipment (i.e., vehicles). Halton Region will provide $4,515,403 in contributed capital for this project.

The total incremental annual revenue requirement associated with the ICM request is $151,229. Burlington Hydro proposed recovery of the incremental annual revenue requirement through ICM rate riders effective January 1, 2025 to December 31, 2025.

The expected start date of the project is January 1, 2025, and the in-service date is December 31, 2025.

ICM Criteria

Materiality

To satisfy the materiality requirement in the ICM policy, a distributor's application must meet three criteria. The application must first meet the materiality threshold, which determines a distributor's maximum eligible capital funding. Secondly, the distributor needs to show that the project is not a minor expenditure when compared to its overall capital budget. Lastly, the incremental funding must have a significant influence on distributor's operations.

Materiality Threshold

The OEB uses the materiality threshold formula which considers both the growth of the utility and the inflationary increase since the last rebasing year[34], to determine the maximum eligible incremental capital amount.[35]

Burlington Hydro used the OEB-approved materiality threshold formula to arrive at a threshold capital expenditure value of $11,771,200. Burlington Hydro's 2025 capital forecast is $16,891,993. The total net cost of the project, not including capital contributions, is $5,563,693. Based on the 2025 capital forecast and the calculated materiality threshold, the maximum eligible incremental capital amount is $5,120,792. Burlington Hydro is requesting the maximum eligible incremental capital amount of $5,120,792 for the ICM project.

OEB staff and VECC submitted that Burlington Hydro had met the materiality threshold criterion.[36]

Findings

The OEB notes that Burlington Hydro used the OEB-approved materiality threshold formula to arrive at a threshold capital expenditure value of $11,771,200 and requested the maximum eligible incremental capital amount of $5,120,792. The OEB finds that the application meets the materiality threshold.

Project-Specific Materiality Threshold

The project-specific materiality threshold criterion states that minor expenditures in comparison to the overall capital budget should be considered ineligible for Advanced Capital Module or ICM treatment, and a certain degree of project expenditure over and above the OEB-defined threshold calculation is expected to be absorbed within the total capital budget.[37]

Burlington Hydro states that the ICM project is material on a project-specific basis. The project is equal to 33% of Burlington Hydro's total 2025 capital expenditure forecast of $16,891,993.

OEB staff submitted that Burlington Hydro's ICM project constituted a significant portion of the utility's overall capital expenditure forecast and therefore satisfied the project-specific materiality threshold. VECC also submitted that the cost of the ICM project

[34] Burlington Hydro last rebased in 2021 (EB-2020-0007)
[35] Chapter 3 Filing Requirements, section 3.3.2.2
[36] OEB Staff Submission, p. 3, and VECC Submission, p.3
[37] Funding of Capital Report, p. 17

represented 33% of the 2025 capital budget and that Burlington Hydro had met the materiality criterion.[38]

Findings

The OEB finds that the 2025 ICM request is material on a project-specific basis relative to Burlington Hydro's 2025 capital expenditure budget and therefore meets the project-specific materiality threshold criterion.

Significant Influence on Operations

The ICM policy provides that any amount being requested for ICM funding must clearly have a significant influence on the distributor's operations.[39]

Burlington Hydro stated that the road widening project made up a significant portion of its total capital expenditure forecast and that the project would have a significant influence on company operations.

OEB staff and VECC submitted that this project will significantly influence the company's operations given the size of the financial expenditure.[40]

Findings

The OEB finds that the ICM project will have a significant influence on Burlington Hydro's operations.

Need

To satisfy the need requirement in the ICM policy, a distributor's application must pass the Means Test; amounts must be based on discrete projects and should be directly related to the claimed driver; and the amounts must be clearly outside of the base upon which the rates were derived.[41]

Means Test

Under the Means Test, if a distributor's regulated Return on Equity (ROE) exceeds 300 basis points above the deemed ROE embedded in the distributor's rates, then funding for any incremental capital project will be disallowed. Burlington Hydro stated that its

[38] OEB Staff Submission, p. 3 and VECC Submission, p. 3
[39] Funding of Capital Report, p. 17
[40] OEB Staff Submission, p. 5 and VECC Submission, p. 3
[41] Funding of Capital Report, p. 17

2023 actual ROE was 8.11%, which is 0.23% (23 basis points) lower than its deemed ROE of 8.34%.

OEB staff and VECC submitted that Burlington Hydro had not exceeded its deemed rate of return by 300 basis points and, therefore, passed the Means Test.[42]

Findings

The OEB finds that Burlington Hydro passes the Means Test as the actual 2023 ROE of 8.11% is lower than the deemed ROE of 8.34%.

Discrete Project

The ICM policy provides that incremental capital funding is for discrete projects and not for ongoing capital programs. Burlington Hydro stated that the ICM project is a distinct, non-discretionary System Access project, and is unrelated to Burlington Hydro's recurring annual capital projects.

OEB staff submitted that the proposed ICM project is discrete and unrelated to ongoing capital programs.[43] Similarly, VECC submitted that the proposed ICM project is a discrete externally driven and non-discretionary road widening project.[44]

Findings

The OEB finds that the relocation project is discrete, not part of a typical annual capital program, and it meets the discrete project criterion.

Directly Related to the Claimed Driver

Burlington Hydro states that the driver of the ICM project is a mandatory request by Halton Region to accommodate the Dundas Street Road Widening Project (Guelph Line West to Kerns Road and Guelph Line East to Northampton Boulevard). The project involves relocating Burlington Hydro's electrical distribution assets on Dundas Street to comply with the request.

OEB staff and VECC submitted that the incremental capital request for relocating distribution assets directly related to the claimed drivers identified by Burlington Hydro.[45]

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[42] OEB Staff Submission, p. 5 and VECC Submission, p. 3
[43] OEB Staff Submission, p. 5
[44] VECC Submission, p. 3
[45] OEB Staff Submission, p. 5 and VECC Submission, p. 3

Findings

The OEB finds that the incremental capital request for relocating distribution assets directly related to the claimed drivers identified by Burlington Hydro.

Outside of Base Upon Which Rates Were Derived

Burlington Hydro stated that the ICM project was not included in the capital expenditures approved in Burlington Hydro's 2021 cost of service application[46] and, as such, is not funded through existing rates.

OEB staff submitted that the ICM amounts are not fully outside of the base upon which rates were derived and therefore should be reduced.[47] OEB staff noted that it is appropriate to evaluate what constitutes a normal level of capital expenditure for pole and transformer replacement included in base rates by looking at asset condition. In response to an interrogatory, Burlington Hydro identified four poles and one transformer being replaced in the ICM project as being in Poor condition.[48] OEB staff submitted that the four poles and one transformer in Poor condition would be expected to be replaced in the near-term and should be accounted for as part of base rates in Burlington Hydro's 2021 Distribution System Plan (DSP), and that the ICM amount should be reduced by at least $197,757 (approximately 4%), representing the estimated value of replacing those items.[49]

OEB staff highlighted a similar approach taken by the OEB in a Z-factor application[50] for Elexicon Energy Inc. (Elexicon Energy) related to expenditures associated with the restoration of electricity service following a derecho storm event. In its Decision and Order in the Z-factor application, the OEB reduced Elexicon Energy's Z-factor cost claim in the Poles and Overhead Conductor category by 12% (or $322,000) on the basis that the poles classified as Poor and Fair-Poor would have been replaced within one to two years.[51] OEB staff argued that although this precedent was for a Z-factor claim, a similar approach is appropriate in the case of the poles and transformers in Poor condition in Burlington Hydro's ICM request.

VECC also submitted that the ICM request should be reduced by approximately 4% ($197,757) to reflect the estimated value of replacing the four poles and one transformer identified as being in Poor condition. VECC stated that such costs should be accounted

[46] EB-2020-0007
[47] OEB Staff Submission, p. 6
[48] Burlington Hydro Interrogatory Response to Staff-17, October 18, 2024
[49] OEB Staff Submission, p. 6
[50] EB-2022-0317
[51] EB-2022-0317, Decision and Order, June 15, 2023, p. 12

for in Burlington Hydro's annual pole and transformer replacement programs under System Renewal.[52]

Burlington Hydro disagreed with the OEB staff and VECC submissions.[53] Burlington Hydro stated that the four poles and one transformer in Poor condition would not have been replaced in the near-term and the replacement was not accounted for as part of base rates in Burlington Hydro's 2021 DSP. Burlington Hydro noted that its pole and transformer replacement programs underpinning base rates had different cost drivers than the ICM project and were budgeted separately through Burlington Hydro's capital planning process. Burlington Hydro added that its 2021 DSP identified 412 poles in Poor condition and 238 in Very Poor condition, and proposed to replace 100 poles per year. Burlington Hydro explained that some of the poles in Poor or Very Poor condition would not be replaced at all over the 2021-2025 DSP period as it had not received funding in rates to replace 650 poles over a five-year period.

Burlington Hydro further submitted that Elexicon Energy's Z-factor application was not a valid comparison for its ICM funding request.[54] Unlike Elexicon Energy, Burlington Hydro stated that it did not typically replace assets in Poor or Fair-Poor condition within one to two years. The utility noted that it has records of the condition of all assets that need to be replaced, and it is already forecasting to exceed its planned capital program in the years leading up to its next rebasing.

VECC also submitted that Burlington Hydro's 2021 net capital forecast approved by the OEB in its 2021 cost of service application included a net base budget of $3,035,948 for the Dundas St. Road Widening Project (Walkers Line to Appleby Line) and $1,500,000 for the Waterdown Road Widening Project, which were included in the calculation of base rates.[55] Asymmetrical capital variance accounts were established for both projects to capture the variances between the 2021 budgeted and actual net capital additions in the 2021 Test Year and the subsequent IRM period for each project. The 2021 Dundas St. Road Widening Project (Walkers Line to Appleby Line) was not completed in 2021 and subsequent years because the project was delayed by the road authority. The Waterdown Road Widening project proceeded, but at a higher cost due to an additional scope of work identified during project construction, which was partially funded by the road authority. VECC submitted that Burlington Hydro's ICM request should be reduced by $1,500,000 to account for the amount included in 2021 base rates for road widening projects that will not be refunded to customers.

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[52] VECC Submission, p. 5
[53] Burlington Hydro Reply Submission, p. 7
[54] Ibid., p. 9
[55] VECC Submission, p. 4

In its reply submission, Burlington Hydro disagreed with the $1,500,000 reduction.[56] Burlington Hydro stated that the 2021 Waterdown Road Widening Project is a discrete project, distinct from the ICM project. Burlington Hydro submitted that the full $1,500,000 included in base rates for the 2021 Waterdown Road Widening Project was spent and a reduction based on road widening projects included in 2021 base rates was not appropriate.

Findings

The OEB finds that the ICM amount requested by Burlington Hydro is not entirely outside of the base upon which rates were derived.

The OEB agrees with OEB staff and VECC that the four poles and one transformer identified as being in Poor condition should be accounted for as part of base rates in Burlington Hydro's 2021 DSP. Additionally, the OEB acknowledges that Elexicon Energy's Z-factor application, where the cost claim for poles in Poor condition was reduced, sets a valid precedent in this case.

Based on the evidence provided, the OEB finds that the ICM amount requested by Burlington Hydro should be reduced by $197,757 (approximately 4%). This represents the estimated cost of replacing the four poles and one transformer in Poor condition. The OEB disagrees with Burlington Hydro's assertion in its reply submission that a project cannot be discrete and unrelated to ongoing capital programs, and at the same time be accounted for as part of the pole replacement or transformer replacement programs underpinning base rates. Even if Burlington Hydro did not intend to replace the four poles and one transformer identified in this project within one to two years, the OEB notes that any capital funding approved for the broader project must consider the need for prudent planning and avoid duplicative or premature expenditures related to assets identified for replacement in the near term. The OEB expects all utilities to give full and serious consideration to the burden their capital funding requests place on ratepayers and to ensure their proposals reflect this responsibility.

Regarding VECC's request for a $1,500,000 reduction in ICM funding, the OEB disagrees with this reduction. The OEB notes that the $1,500,000 amount for the 2021 Waterdown Road Widening Project was included in the calculation of base rates.[57] The project was completed at a higher cost than budgeted, resulting in no entry to the asymmetrical capital variance account (Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account). Consequently, there is no funding left from this project to be refunded to

[56] Burlington Hydro Reply Submission, p. 10
[57] VECC Submission, p. 4

ratepayers. Furthermore, based on the information provided in this proceeding, the 2021 Waterdown Road Widening Project appears to be unrelated to the ICM project. The former addressed work done on Waterdown Road North, from Craven Avenue to Mountain Brow Road,[58] whereas the ICM project pertains to work on Dundas Street, from Guelph Line to Kerns Road and from Northampton Boulevard to Guelph Line.[59] The OEB finds that VECC's proposed $1,500,000 reduction lacks sufficient justification.

The OEB also notes that the Dundas St. Road Widening Project (Walkers Line to Appleby Line) was not completed in 2021 or subsequent years because the project was delayed by the road authority.[60] Based on the Accounting Order in Burlington Hydro's 2021 Decision and Order, the revenue requirement of the net base budget of $3,035,948 should have been recorded in the asymmetrical capital variance account (Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account) with the accrued carrying charges for disposition at Burlington Hydro's next rebasing application.[61] The OEB finds that instead of waiting to return the balance to ratepayers at Burlington Hydro's next rebasing application, Burlington Hydro should use the entire balance in that account, as of December 31, 2023 including the carrying charges up until Q4 2024, to offset some of the funding required for the ICM project. The OEB recognizes that this will clear the balance in this account earlier than anticipated in the 2021 Decision and Order, but this represents a better outcome for the utility and its rate payers. Burlington Hydro's need for ICM funding is lower, and rate payers do not have to wait until the rebasing proceeding to get their refund. Burlington Hydro is directed to request the discontinuance of the account at its next rebasing application. The remainder of the approved ICM funding is to be recovered through a rate rider.

Prudence

The ICM policy states that the amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.[62]

Burlington Hydro stated that the project represented prudent investments and delivered the most cost-effective option for customers based on an assessment of alternatives. Burlington Hydro considered three project alternatives: status quo, like for like, and

[58] Burlington Hydro DSP, Appendix 1
[59] Manager's Summary, Appendix D
[60] Burlington Hydro Interrogatory Responses, VECC – 4, f)
[61] EB-2020-0007, Decision and Rate Order, Schedule C
[62] Funding of Capital Report, p. 17

upgrade. Burlington Hydro indicated that the upgrade alternative was the only viable option.

OEB staff submitted that not all amounts to be incurred were prudent and expressed a concern with the cost estimate provided by Burlington Hydro.[63]

Burlington Hydro indicated that material costs were estimated using its most recent purchase prices, and labour and equipment costs were estimated using a quote from a contractor who has completed a relocation project for the utility in the past. Burlington Hydro also stated that it expects the actual costs for this project to be within 75-125% of the estimate.[64]

OEB staff filed an interrogatory[65] asking Burlington Hydro to provide a cost-per-pole replaced and per-transformer replaced, and compare it to any previous comparable relocation project done either by Burlington Hydro or a comparable distributor and to explain the variances. Burlington Hydro provided an estimated cost-per-pole replaced and per-transformer replaced for the requested ICM project (2025 Dundas St Road Widening), and a comparable 2021 Waterdown Road Widening Project as shown in Table 8.1 below.[66]

Table 8.1: Estimate Cost Per Unit Replaced

Project	Cost per Pole	Cost per Transformer	Cost per km of Underground Cable
2025 Dundas St Road Widening	$38,754	$42,741	$381,008
Waterdown Road Widening	$28,291	$12,062	$362,712
Variance ($)	**$10,463**	**$30,678**	**$18,296**

OEB staff noted that the requested ICM project had significantly higher costs than the comparable project for cost per pole (37% higher), transformer (254% higher), and underground cable (5% higher) replaced.[67] OEB staff acknowledged that each relocation project is unique, with varying design and scope differences that inherently

[63] OEB Staff Submission, pp. 7-8
[64] Burlington Hydro Interrogatory Response to Staff-15, October 18, 2024
[65] Staff-15 Interrogatory
[66] Burlington Hydro Interrogatory Response to Staff-15, October 18, 2024
[67] OEB Staff Submission, p. 8

affect the costs, but it could not ignore the 254% increase in cost per transformer replaced when compared to the Waterdown Road Widening Project.

OEB staff examined two scenarios to account for the inflationary increases from 2021 to 2025, based on the Waterdown Road Widening project's cost of $12,062 per transformer replaced.[68] The first scenario inflated the cost per transformer by the OEB-approved inflation parameters, and the second scenario inflated it by the Statistics Canada's Power, Distribution and Other Transformers Price Index (Statistics Canada Index). OEB staff noted that the cost per transformer identified in the ICM project was 205% higher than the inflated cost calculated in the scenario using OEB-approved inflation parameters ($14,028.76) and 195% higher than the inflated cost calculated in the scenario using the Statistics Canada Index ($19,269.64).

OEB staff submitted that there was a lack of prudence in the cost estimate process and the resulting requested costs, and the ICM amount should be reduced by $160,692 (approximately 3%) because:

- The cost per transformer replaced in the ICM project is still substantially higher than the comparable project even after accounting for the higher levels of inflation using the Statistics Canada Index[69]
- The estimated labour and equipment costs are based solely on a quote from one contractor and do not reflect a competitive procurement process[70]

Table 8.2 below shows the calculation of the proposed ICM funding reduction.

OEB staff proposed that the cost per transformer of $42,741, as seen in Table 8.2, should be reduced to $35,089, to bring the cost closer to the inflated costs calculated using the OEB-approved inflation parameters and the Statistics Canada Index.

Table 8.2: Proposed Reduction of Costs per Transformer Replaced

	# of Transformers to be Replaced	Cost per Transformer	Total Cost
Requested	21	$42,741	$897,561
Proposed Reduction	21	$35,089	$736,869
Total Reduction			**$160,692**

[68] OEB Staff Submission, p. 8
[69] Ibid., p. 9
[70] Ibid., p.10

VECC submitted that it was also concerned with the lack of prudence in the cost estimate process provided by Burlington Hydro.[71] Burlington Hydro provided the unit cost per circuit kilometer for overhead and underground for the Waterdown Road Widening Project which was included in the 2021 capital forecast. VECC applied these unit costs to the circuit kilometers in the ICM project as per Table 8.3 below.

Table 8.3: ICM Cost Estimate Based on Waterdown Road Widening Project Unit Costs/km

2025 ICM Project Description Compared to Dundas Street	Circuit km Overhead	Forecast Overhead $	Circuit km Underground	Forecast Underground $	Total	ICM Request
Dundas Street Road Widening – Guelph Line to Kerns Road	23	$4,623,679	1	$181,274	$4,804,953	$8,055,103
Dundas Street Road Widening – Northampton Blvd to Guelph Line	20	$4,020,590	4	$725,097	$4,745,687	$2,023,992
Total	**43**	**$8,644,269**	**5**	**$906,371**	**$9,550,639**	**$10,079,095**

VECC noted that the requested ICM project cost ($10,079,095) is slightly higher than the estimate calculated using unit costs for overhead and underground work from the comparable Waterdown Road Widening Project ($9,550,639).[72] VECC also expressed concern with the significant difference in costs between the two sections of the project. VECC submitted that the ICM amount should be reduced by a further 3% ($160,692) to

[71] VECC Submission, p. 6
[72] Ibid.

reflect the lack of prudence in the cost estimate process and the resulting requested costs.[73]

In its reply, Burlington Hydro stated that total costs and costs per transformer for the 2021 Waterdown Road Widening project cannot be compared to those of the ICM project.[74] Burlington Hydro interpreted the interrogatory from OEB staff, which requested a cost comparison to a comparable relocation project, to mean comparable only for project type. Both projects are road widening projects initiated by a road authority, requiring relocation of distribution system infrastructure, but for the most part this is where the similarities end. Burlington Hydro stated that the cost per transformer was higher in the ICM project compared to the 2021 Waterdown Road Widening project for the following reasons:

- The ICM project requires more pad-mount transformers which are significantly more expensive than pole-mount transformers
- There are more transformers with a higher nameplate rating that must be replaced, which are also more expensive
- As part of Burlington Hydro's response to interrogatory Staff-15 (d), it counted three transformers installed as banks (where each bank has three transformers grouped together) as only three transformers instead of nine, which resulted in a higher average transformer cost

Burlington Hydro reported that the average cost per transformer for the ICM project was $42,741, which, when converted to 2021 dollars, amounts to $26,175.[75] Burlington Hydro stated that this number was a more appropriate comparison than the $12,062 cost per transformer replaced in the Waterdown Road Widening Project. Burlington Hydro explained that the $26,175 amount reflected the cost of the individual transformers listed on the relocation design's bill of materials, which are different transformers than those used for the Waterdown Road Widening Project. As such, Burlington Hydro submitted that the $26,175 cost per transformer should be used as the starting point when inflating costs to 2025 dollars.[76] Burlington Hydro also indicated that it used the Statistics Canada Index to arrive at $41,815 in 2025 dollars, which it stated is within 2% of the average cost per transformer in the ICM project's cost estimate.[77]

Burlington Hydro added that its cost estimate was not developed using average unit costs for transformers, poles, or cable, but by referencing the bill of materials from the

[73] VECC Submission, p. 6
[74] Burlington Hydro Reply Submission, p. 13
[75] Burlington Hydro Reply Submission, p.15
[76] Ibid., p. 16
[77] Ibid., p. 17

utility relocation design and Burlington Hydro's most recent purchase price.[78] It stated that this bottom-up approach helps reflect the unique scope and design of the ICM project.

Burlington Hydro also stated that it updated the cost estimate of the ICM project from $5,800,709 to $5,563,693 when more recent information became available, demonstrating its commitment to improving the accuracy of cost estimates.[79]

In response to OEB staff's submission regarding the lack of a competitive procurement process, Burlington Hydro explained that it had not completed a competitive procurement process for the ICM project, as the decision on whether to construct internally or externally was still pending.[80] It also added that the estimate it received from a contractor was reviewed against other past projects for reasonableness and prudence.

To address VECC's concern with the significant difference in costs between the two sections of the project, Burlington Hydro explained that there are longer linear kilometers of the section from Guelph Line to Kerns Road which results in more than twice as many assets that must be installed in this section of the project.[81] Burlington Hydro did not address VECC's observation that the requested ICM project cost is slightly higher than the estimate calculated using unit costs for overhead and underground work from the comparable Waterdown Road Widening Project.

Burlington Hydro submitted that there was no lack of prudence in its cost estimate process.

Findings

The OEB finds that not all amounts to be incurred are prudent.

Burlington Hydro provided an estimated cost per pole replaced and per transformer replaced for the requested ICM project, as well as for a comparable 2021 Waterdown Road Widening Project.[82] OEB staff adjusted the cost of the 2021 Waterdown Road Widening Project using the OEB-approved inflation parameters and the Statistics Canada Power, Distribution and Other Transformers Price Index (Statistics Canada Index).[83] The OEB is concerned that, even after accounting for higher inflation levels

[78] Burlington Hydro Reply Submission, p. 18
[79] Ibid.
[80] Ibid., p. 19
[81] Ibid., p. 21
[82] Burlington Hydro Interrogatory Response to Staff-15, October 18, 2024
[83] OEB Staff Submission, p. 8

with the Statistics Canada Index, the cost per transformer replaced in the ICM project remains significantly higher than in the comparable project.

Additionally, the OEB notes that Burlington Hydro had not completed a competitive procurement process for the labor and equipment costs, raising further concerns about cost prudence.[84]

Given these considerations, the OEB agrees with OEB staff and VECC that there was a lack of prudence in the cost estimate process and the resulting requested costs. In light of the lack of prudence on the part of Burlington Hydro in this case, the OEB considers it appropriate to further reduce the ICM amount by $160,692 (approximately 3%).

[84] Burlington Hydro Reply Submission, p. 19

9. IMPLEMENTATION

This Decision and Order is accompanied by a Rate Generator Model, applicable supporting models, and a Tariff of Rates and Charges (Schedule A). The Tariff of Rates and Charges in Schedule A incorporates the OEB's findings in this Decision and Order with the exception of the ICM rate rider. The OEB is directing Burlington Hydro to prepare a Draft Rate Order that includes an ICM rate rider reflecting the OEB's findings. The OEB anticipates replacing the Tariff of Rates and Charges in Schedule A following its review of the Draft Rate Order. The Rate Generator Model also incorporates the following regulatory rates and charges set out in Table 9.1.

Table 9.1: Regulatory Rates and Charges

Rates	per kWh ($)
Rural or Remote Electricity Rate Protection (RRRP)	0.0015
Wholesale Market Service (WMS) billed to Class A and B Customers	0.0041
Capacity Based Recovery (CBR) billed to Class B Customers	0.0004
Charges	**($)**
Smart Metering Entity Charge	0.42
microFIT Charge	5.00
Standard Supply Service - Administrative Charge (if applicable)	0.25

Each of the rates is a component of the "Regulatory Charge" on a customer's bill, established annually by the OEB through a separate, generic order. The RRRP and WMS rates were set by the OEB on December 10, 2024.[85]

The Smart Metering Entity Charge is a component of the "Distribution Charge" on a customer's bill, established by the OEB through a separate order. The Smart Metering Entity Charge was set by the OEB on September 8, 2022.[86]

[85] EB-2024-0282, Decision and Order, December 10, 2024
[86] EB-2022-0137, Decision and Order, September 8, 2022

In the *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*,[87] the OEB indicated that it will review the default province-wide microFIT charge annually to ensure it continues to reflect actual costs in accordance with the established methodology. On November 19, 2024, the OEB issued a letter advising electricity distributors that the microFIT charge shall be $5.00 for the duration of the 2025 rate year (January 1 to December 31, 2025).[88]

[87] EB-2010-0219, Report of the Board “Review of Electricity Distribution Cost Allocation Policy”, March 31, 2011
[88] OEB Letter, “Review of Fixed Monthly Charge for microFIT Generator Service Classification”, issued November 19, 2024

10. ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Schedule A of this Decision and Order is approved effective January 1, 2025. The Tariff of Rates and Charges will apply to electricity consumed or estimated to have been consumed on and after January 1, 2025.

2. Burlington Hydro Inc. shall file with the OEB and forward to intervenors a Draft Rate Order with a proposed Tariff of Rates and Charges attached that reflects the OEB's findings in this Decision and Order, no later than January 9, 2025. Burlington Hydro Inc. shall also file a revised ICM model, supported by the revised ICM funding, offset by the 2023 balance including carrying charges up to Q4 2024 in the variance Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account. Burlington Hydro is to show the calculation of the balance in the variance account. Burlington Hydro shall also file customer rate impacts and detailed information in support of the calculation of final rates in the Draft Rate Order.

3. Intervenors and OEB staff shall file any comments on the Draft Rate Order with the OEB, and forward to Burlington Hydro Inc., no later than January 17, 2025.

4. Burlington Hydro Inc. shall file with the OEB and forward to intervenors, responses to any comments on its Draft Rate Order no later than January 24, 2025.

Parties are responsible for ensuring that any documents they file with the OEB, such as applicant and intervenor evidence, interrogatories and responses to interrogatories or any other type of document, **do not include personal information** (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Please quote file number, **EB-2024-0010** for all materials filed and submit them in searchable/unrestricted PDF format with a digital signature through the OEB's online filing portal.

- Filings should clearly state the sender's name, postal address, telephone number and e-mail address.
- Please use the document naming conventions and document submission standards outlined in the Regulatory Electronic Submission System (RESS)

Document Guidelines found at the File documents online page on the OEB's website.

- Parties are encouraged to use RESS. Those who have not yet set up an account, or require assistance using the online filing portal can contact registrar@oeb.ca for assistance.
- Cost claims are filed through the OEB's online filing portal. Please visit the File documents online page of the OEB's website for more information. All participants shall download a copy of their submitted cost claim and serve it on all required parties as per the Practice Direction on Cost Awards.

All communications should be directed to the attention of the Registrar and be received by end of business, 4:45 p.m., on the required date.

With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Yaroslav Paliy at Yaroslav.Paliy@oeb.ca, and OEB Counsel, James Sidlofsky at James.Sidlofsky@oeb.ca.

Email: registrar@oeb.ca
Tel: 1-877-632-2727 (Toll free)

DATED at Toronto, December 17, 2024

ONTARIO ENERGY BOARD

Nancy Marconi
Digitally signed by Nancy Marconi
Date: 2024.12.17 16:07:56 -05'00'

Nancy Marconi
Registrar

SCHEDULE A

DECISION AND ORDER

BURLINGTON HYDRO INC.

TARIFF OF RATES AND CHARGES

EB-2024-0010

DECEMBER 17, 2024

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0010

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	$	32.64
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Rate Rider for Disposition of Global Adjustment Account (2025) - effective until December 31, 2025 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2025) - effective until December 31, 2025	$/kWh	0.0007
Rate Rider for Disposition of Capacity Based Recovery Account (2025) - effective until December 31, 2025 Applicable only for Class B Customers	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0128
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0096

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, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0010

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	$	29.29
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0193
Rate Rider for Disposition of Global Adjustment Account (2025) - effective until December 31, 2025 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2025) - effective until December 31, 2025	$/kWh	0.0009
Rate Rider for Disposition of Capacity Based Recovery Account (2025) - effective until December 31, 2025 Applicable only for Class B Customers	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0087

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, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0010

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	$	78.66
Distribution Volumetric Rate	$/kW	3.8537
Rate Rider for Disposition of Global Adjustment Account (2025) - effective until December 31, 2025 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2025) - effective until December 31, 2025	$/kW	0.3483
Rate Rider for Disposition of Capacity Based Recovery Account (2025) - effective until December 31, 2025 Applicable only for Class B Customers	$/kW	0.0706
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	5.0599
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	3.7940

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2025

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2024-0010

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, 2025

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EB-2024-0010

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
Distribution Volumetric Rate	$/kWh	0.0188
Rate Rider for Disposition of Capacity Based Recovery Account (2025) - effective until December 31, 2025 Applicable only for Class B Customers	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2025) - effective until December 31, 2025	$/kWh	0.0009
Retail Transmission Rate - Network Service Rate	$/kWh	0.0123
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0087

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, 2025

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EB-2024-0010

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)	$	0.65
Distribution Volumetric Rate	$/kW	4.6705
Rate Rider for Disposition of Global Adjustment Account (2025) - effective until December 31, 2025 Applicable only for Non-RPP Customers	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Accounts (2025) - effective until December 31, 2025	$/kW	0.3435
Rate Rider for Disposition of Capacity Based Recovery Account (2025) - effective until December 31, 2025 Applicable only for Class B Customers	$/kW	0.0725
Retail Transmission Rate - Network Service Rate	$/kW	3.6978
Retail Transmission Rate - Line Connection Service Rate	$/kW	2.7000

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-2024-0010

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

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

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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
Returned cheque (plus bank charges)	$	15.00

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	$	39.14
(with the exception of wireless attachments)		

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

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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.

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.

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	$	121.23
Monthly Fixed Charge, per retailer	$	48.50
Monthly Variable Charge, per customer, per retailer	$/cust.	1.20
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.71
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.71)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.61
Processing fee, per request, applied to the requesting party	$	1.20
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)	$	4.85
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)	$	2.42

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	1.0382
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0279