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

DECISION AND RATE ORDER

EB-2020-0007

BURLINGTON HYDRO INC.

Application for electricity distribution rates and other charges beginning May 1, 2021

BEFORE: Emad Elsayed
Presiding Commissioner

Michael Janigan
Commissioner

April 15, 2021

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1 INTRODUCTION AND SUMMARY

Burlington Hydro Inc. filed an application with the Ontario Energy Board (OEB) to change its electricity distribution rates effective May 1, 2021. Under section 78 of the *Ontario Energy Board Act, 1998*[1], a distributor must apply to the OEB to change the rates it charges its customers.

Burlington Hydro provides electricity distribution services to approximately 68,000 residential, commercial and streetlight and unmetered scattered load customers in the City of Burlington.

The OEB's *Renewed Regulatory Framework for Electricity*[2] and *Handbook for Utility Rate Applications*[3] provide distributors with performance-based rate application options that support the cost-effective planning and efficient operation of a distribution network. This framework provides an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

Burlington Hydro asked the OEB to approve its rates for five years using the Price Cap Incentive rate-setting option. Following the OEB's decision in this application, Burlington Hydro can apply to have its rates adjusted mechanistically in each of the following four years (2022-2025) based on inflation and OEB's assessment of Burlington Hydro's efficiency.

A settlement conference was held on February 22, 23 and 24 2021, which was attended by Burlington Hydro and the intervenors in this proceeding; namely, Consumers Council of Canada (CCC), Distributed Resource Coalition (DRC), Energy Probe Research Foundation (Energy Probe), Environmental Defence, School Energy Coalition (SEC), and Vulnerable Energy Consumers Coalition (VECC) (collectively, the parties). OEB staff also attended the conference but was not a party to the settlement proposal. On March 17, 2021, Burlington Hydro filed a settlement proposal, which represented a complete settlement on all issues. OEB staff filed its submission on the settlement proposal on March 24, 2021.

Having considered the settlement proposal and submissions of OEB staff, the OEB approves the settlement proposal as filed.

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[1] *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, Schedule B
[2] Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012
[3] Handbook for Utility Rate Applications, October 13, 2016

As a result of this Decision and Rate Order, it is estimated that for a typical residential customer with a monthly consumption of 750 kWh, the total bill impact will be an increase of $2.35 per month before taxes and the Ontario Electricity Rebate, or 1.66%.

The OEB also makes its determination on Burlington Hydro's confidentiality request in this Decision and Rate Order. The OEB finds the METSCO capital investment Evaluation Tool and Project Prioritization Tool User Manual shall be considered confidential and remain redacted from the public record. The remainder of the information, except redacted "personal information" as that phrase is defined in *Freedom of Information and Protection of Privacy Act* (FIPPA), shall be placed on the public record.

2 THE PROCESS

Burlington Hydro filed an application on October 30, 2020 for 2021 rates under the Price-Cap Incentive rate-setting option of the *Renewed Regulatory Framework for Electricity*. The application was accepted by the OEB as complete on November 13, 2020. The OEB issued a Notice of Hearing on November 17, 2020, inviting parties to apply for intervenor status. CCC, DRC, Energy Probe, Environmental Defence, SEC, and VECC were granted intervenor status and cost award eligibility. OEB staff also participated in this proceeding.

The OEB received seven letters of comment, which were placed on the record of this proceeding. These comments were taken into consideration during the evaluation of the application by the OEB.

The OEB issued Procedural Order No. 1 on December 11, 2020. This order established, among other things, the timetable for a written interrogatory discovery process and a settlement conference.

Burlington Hydro responded to the interrogatories submitted by OEB staff and the intervenors. The OEB issued its approved Issues List on February 12, 2021.

A settlement conference took place on February 22, 23 and 24 2021. In accordance with Procedural Order No. 1, Burlington Hydro filed a settlement proposal with the OEB on March 17, 2021.

3 DECISION

3.1 Settlement Proposal

The settlement proposal addressed all issues on the OEB's approved Issues List for this proceeding and represented the parties' full settlement on all the issues. The settlement proposal contained further explanation and rationale on specific issues for the OEB to consider.

Key features of the settlement proposal included:

- Reduction of 2021 test year net capital expenditures by $0.5 million resulting in a revised budget of $13.5 million
- Reduction of OM&A envelope by $0.9 million resulting in a revised budget of $20.6 million
- Agreement on a service revenue requirement of $37.0 million and a base revenue requirement of $33.9 million
- Target five-year average total system losses at 3.4% over 2021-2025. Burlington Hydro will file a plan with the OEB when complete over the course of 2021-2022, to reduce distribution losses as much as reasonably possible though cost-effective measures, and to implement as many of these cost-effective measures as possible during 2022 to 2025.
- Tracking of two new reliability metrics and three new unit cost metrics, as well as tracking of proactive versus reactive asset replacement (quantity and total expenditures for both reactive and proactive replacements) for identified asset classes
- Creation of two separate asymmetrical capital variance accounts to track the variance in the revenue requirement from the budgeted and actual net capital additions in the 2021 test year and the resulting impact through the incentive rate-setting mechanism period for two System Access projects (Dundas Street and Waterdown Road road widenings)
- Load forecast of 1,547 GWh, 2,350 MW, and 86,461 customers and connections
- Disposition of Group 1 Deferral and Variance Account (DVA) balances (debit of $2,433,347) as of December 31, 2019 on an interim basis, over two years
- Disposition of Group 2 and other DVA balances (debit amount of $733,207) as of December 31, 2019, on a final basis, over two years

OEB staff filed a submission on March 24, 2021, supporting the settlement proposal.

Findings

The OEB accepts the settlement proposal as filed. The OEB finds that implementation of the settlement proposal would be in the public interest and should result in reasonable outcomes for both Burlington Hydro and its customers.

The OEB has the following specific comments on some of the highlights of the settlement proposal.

- The OEB finds that the estimated bill impacts in each rate class resulting from the settlement proposal are reasonable
- The effective date of the rates arising from the settlement proposal of May 1, 2021, is appropriate
- Reduction in Burlington Hydro’s proposed Test Year OM&A spending is reasonable and should not adversely affect Burlington Hydro’s ability to maintain a safe and reliable distribution system in the Test Year
- Reduction in Burlington Hydro’s proposed capital expenditures in the Test Year is reasonable and should not negatively impact Burlington Hydro’s ability to manage its assets
- The OEB acknowledges that Burlington Hydro has identified and pursued operational effectiveness initiatives since its last rebasing application and encourages it to continue pursuing such initiatives as identified in this application

The approved settlement proposal is attached as Schedule B to this Decision and Rate Order. The approved accounting orders are attached as Schedule C.

3.2 Confidential Treatment Requests

Non-Benchmark Report Confidentiality Requests

In Interrogatory Responses to 2-Staff-17(c) and 2-SEC-14(b), Burlington Hydro requested confidential treatment of the calculations and assumptions that were used in the METSCO Evaluation Tool. OEB staff did not oppose the requested confidential treatment of redacted information. SEC opposed the confidential treatment of this information and submitted that the “underlying assumptions and calculations used for the purpose of capital project prioritization tools are regularly placed on the public record and usually are included in a utility’s DSP”.

In Interrogatory Responses to CCC-13, DSP-DRC-4 and 4-VEC-46a), Burlington Hydro redacted information related to total costs of customer engagement services provided by Innovative Research Group (Innovative) and METSCO’s tools, stating project details and costs could reasonably be expected to prejudice and interfere with the suppliers’ future negotiations. OEB staff and SEC noted that similar information was made publicly available in previous OEB proceedings (CCC-13, DSP-DRC-4) or that the basis for the confidentiality claim was not adequately explained (4-VEC-46a). SEC also submitted that the total project costs are not prejudicial to the vendors as the pricing of a specific project is based on many factors.

In its March 5, 2021 reply submission, Burlington Hydro maintained its confidentiality claims over information contained in its responses to interrogatories CCC-13, 2-Staff-17(c), 2-SEC-14(b), and 4-VEC-46a. For DSP-DRC-4, Burlington Hydro advised that it reconsidered its position and was prepared to provide an unredacted version of this interrogatory response on the public record.

Findings

The OEB finds that the information redacted by Burlington Hydro in its interrogatory responses to 2-Staff-17(c) and 2-SEC-14(b) regarding the METSCO capital investment Evaluation Tool and Project Prioritization Tool User Manual shall be considered confidential and shall remain redacted from the public record. The OEB finds that this information contains proprietary and commercially sensitive third-party information such as specific assumptions, equations, data, and calculations applied to some specific capital investment programs. The OEB accepts that the redacted information, if disclosed, would enable a third party to replicate the results at no cost.

The OEB finds that Burlington Hydro has not provided compelling reasons for the redactions made in its responses to interrogatories CCC-13 and 4-VECC-46(a). These interrogatories related to the total cost of Customer Engagement services provided by Innovative and the Program Evaluation Tool and Project Prioritization Tool provided by METSCO, respectively. The OEB finds that similar information, including work by Innovative, has been placed on the public record in previous OEB proceedings.[4] The information in this proceeding includes the total cost of these services as opposed to cost components or cost breakdowns. The OEB finds that disclosure of this information on the public record would not prejudice either Innovative's or METSCO's competitive positions. The OEB finds that these interrogatory responses shall be un-redacted and placed on the public record.

Regarding Burlington Hydro's response to interrogatory DSP-DRC-4, the OEB agrees with Burlington Hydro's decision to re-consider these redactions and agree to placing

[4] EB-2019-0261, Hydro Ottawa Limited 2021-2025 Custom IR Application, June 5, 2020, interrogatory responses CCC-15 and Attachment CCC-33(A)

this interrogatory response on the public record. The OEB finds that this interrogatory response shall be un-redacted and placed on the public record.

Compensation Benchmarking Report Related Confidentiality Requests

Burlington Hydro has sought to redact information from the following four compensation benchmarking reports that it has filed in this proceeding:

1. 2020 MEARIE Management Salary Survey (Report 1)
2. Korn Ferry 2019 Management and Non-Union Employee Pay Report (Report 2)
3. 2016 Willis Towers Watson Incentive Program Review (Report 3)
4. Korn Ferry 2019 CEO Pay Review (Report 4)

Burlington Hydro's proposed redactions arise from either (i) claims that the redacted information is "personal information"; or (ii) claims arising from other confidentiality concerns.

Personal Information

Burlington Hydro argued that Reports 2, 3 and 4 contained "personal information" as that phrase is defined in FIPPA.[5, 6]

OEB staff noted that subject to limited exceptions, the OEB is prohibited from releasing "personal information" as that phrase is defined in FIPPA. OEB staff agreed with Burlington Hydro that information which discloses or will along with already available information allow someone to ascertain, the actual compensation/salary for a specific employee qualifies as "personal information". However, OEB staff noted that the redactions proposed by Burlington Hydro go beyond information that would reveal the compensation/salary amount of a specific employee. OEB staff highlighted the following as examples of information which did not appear to qualify as "personal information": (i) the phone number and email address of a Korn Ferry employee in Reports 2 and 4; and (ii) the names of a number of Burlington Hydro employees in Report 2. SEC also raised concerns about some of the "personal information" redactions arguing that Burlington Hydro had redacted information that includes more than just "personal information".

In its March 5, 2021 reply submission, Burlington Hydro agreed with OEB staff that the phone number and email address of a Korn Ferry employee in Reports 2 and 4; and the names of a number of Burlington Hydro employees in Report 2 do not constitute

[5] The "personal information" contained in Reports 2 and 4 is listed in Table 1 of Burlington Hydro's February 22, 2021 letter to the OEB. The "personal information" contained in Report 3 is set out in Burlington Hydro's February 17, 2021 letter to the OEB.
[6] FIPPA stands for the *Freedom of Information and Protection of Privacy Act.*

"personal information". As part of that same reply submission, Burlington Hydro filed updated copies of Reports 2 and 4 that no longer redacted (i) the phone number and email address of a Korn Ferry employee; and (i) the names of Burlington Hydro employees (Report 2 only).

Findings

The OEB finds that "personal information" as defined in FIPPA and included in Reports 2, 3 and 4 shall remain redacted and shall not be made available to any party, including those who have provided a Declaration and Undertaking. This information consists of compensation information associated with specific positions and individuals.

The OEB further notes that updated copies of Reports 2 and 4 have been filed that disclose certain information that OEB staff identified as appearing to not fit within the definition of "personal information" and therefore a formal direction from the OEB to un-redact that information is not needed.

Other Redactions

Report 1

Burlington Hydro requested Report 1 (i.e., the MEARIE report) be considered confidential arguing that it is an "off the shelf" report that is sold for financial gain and releasing it would result in economic loss for Korn Ferry and MEARIE. Burlington Hydro also argued that disclosure of compensation information contained in Report 1 could prejudice Burlington Hydro's 2021 collective bargaining process.

OEB staff did not support the argument that past compensation information would impact future bargaining activities due to changing economic circumstances, noting that Report 1 contains compiled historic benchmarking data up to 2021 and does not contain past or future compensation strategies specific to Burlington Hydro. OEB staff further submitted that Burlington Hydro had not explained how Report 1 differs in character from previous MEARIE reports that were ordered to be put on the public record in other proceedings. Similarly, SEC noted that previous versions of the MEARIE report have been placed on the public record in previous OEB proceedings, including Burlington Hydro's last cost of service application where the OEB specifically denied confidentiality treatment to a similar MEARIE salary benchmarking report.

Findings

Report 1 contains aggregated information about more than 30 local distribution companies (LDCs) that participated in the benchmarking studies. The information which Burlington Hydro claims to be confidential consists of statistical data for different employee groups based on the collective population of all LDCs. It also includes aggregated group profiles for these LDCs (e.g., budgets, number of employees, number of customers, revenues, etc.).

Most of this is historical information. Although there are some statistics for 2021, again this information is consolidated and/or averaged for all participating LDCs. The OEB is not persuaded that such information would prejudice MEARIE's and Korn Ferry's competitive position and/or Burlington Hydro's 2021 collective bargaining process.

As a result, the OEB finds that it has not been established that financial or economic loss would occur as a result of making Report 1 public. The OEB has placed MEARIE reports on the public record in previous OEB proceedings including the last Burlington Hydro cost of service application.[7]

The OEB finds that Report 1 shall be placed on the public record in its entirety with no redactions.

Reports 2 and 4

Other than "personal information", the remaining redactions in Reports 2 and 4 relate to Burlington Hydro's consolidated market positioning for various components of compensation, Korn Ferry's Hays Points methodology, and Korn Ferry's company database. The database includes a list of companies under the categories of "All Industrial Market" and "Ontario Utilities Market" which participated in compensation cost benchmarking studies.

Neither OEB staff or SEC supported the confidentiality claims for the non-personal information contained in Reports 2 and 4. SEC stated that utility specific compensation benchmarking studies are regularly filed and placed on the public record in OEB proceedings.

OEB staff noted that page 11 of Report 2 (Observations and Key Findings) contains blended information and target compensation positions for management employees. OEB staff submitted that this is high level information should be on the public record, noting that similar information has been placed on the public record in the other OEB proceedings.

[7] EB-2011-0099, Decision on Confidentiality, March 13, 2013, p. 6.; EB-2013-0115/EB-2013-0159/EB-2013-0174, Decision and Order on Confidentiality, May 29, 2014, pp. 7-8, 11.

OEB staff also opposed the redactions relating to Korn Ferry's job evaluation overview[8], noting that similar information about Korn Ferry's job evaluation method is publicly available on its website.

OEB staff also argued that the list of companies contained in Korn Ferry's database[9] should be disclosed on the public record as there has been public disclosure of the same types of information in other proceedings.

In its March 25, 2021 responding submission, Burlington Hydro withdrew its request for confidential treatment of Korn Ferry's job evaluation methodology in light of the publicly available information on Korn Ferry's website. However, Burlington Hydro continued to maintain that confidential treatment is warranted for the redacted information on page 11 of Report 2. Burlington Hydro argued that this information represented consolidated market positioning (All Industrial Market and Ontario Utilities Market) for 30 of its management employees and argued that this information should be afforded confidential treatment because of the relatively large size of this group compared to the total number of employees (about 30%) as well as the potential negative impact of disclosing this information on its collective bargaining process and external hiring salary negotiations.

Burlington Hydro also argued that redactions to certain information regarding Korn Ferry's All Industrial Market and All Ontario Utilities Market database should be upheld as this information consists of commercial material that is consistently treated in a confidential manner by Korn Ferry.

Findings

The OEB finds that the proposed redacted information in Reports 2 and 4 is high level information which, as pointed out by OEB staff, is the same type of information that is either publicly available and/or placed on the public record in other OEB proceedings. With respect to the All Industrial Market and All Ontario Utilities Market database redactions, these are simply lists of a large number of companies that were used for benchmarking purposes. The OEB finds that Burlington Hydro has not established that this information requires confidential treatment.

Regarding redactions related to Korn Ferry's job evaluation overview, the OEB agrees with Burlington Hydro's decision to withdraw its request for confidential treatment of

[8] Report 2: Appendix C – Overview of Job Evaluation, page 57; Report 4: Appendix D – Overview of Job evaluation, page 20.
[9] Report 2: Appendix A – All Industrial Market and Appendix B – Ontario Utilities Market; Report 4: Appendix A – All Industrial Market and Appendix B – Ontario Utilities Market

such information. The OEB finds that the redactions related to Korn Ferry's job evaluation overview shall be un-redacted and placed on the public record.

With respect to the redactions proposed on page 11 of Report 2, the OEB finds that this is high level information that does not identify specific positions or groups of positions in this sample of management employees. The OEB does not agree that disclosure of this information would prejudice Burlington Hydro's competitive position or interfere with its collective bargaining process.

Based on the above, the OEB finds that, other than "personal information", Reports 2 and 4 shall be placed on the public record in their entirety with no redactions.

4 IMPLEMENTATION

The new rates approved in this Decision and Rate Order are to be effective May 1, 2021.

Included in the settlement proposal, Burlington Hydro filed tariff sheets and detailed supporting material, including all relevant calculations showing the impact of the implementation of the settlement on its revenue requirement, allocation of the revenue requirements to its rate classes and the determination of the final rate and rate riders, including bill impacts.

The OEB also made some changes to the formatting on the tariff sheets attached to the settlement proposal in order to ensure consistency with the tariff sheets of other Ontario electricity distributors. The final approved Tariffs of Rates and Charges are attached as Schedule A to this Decision and Rate Order.

CCC, DRC, Energy Probe, Environmental Defence, SEC, and VECC are eligible to apply for cost awards in this proceeding. The OEB has made provision in this Decision and Rate Order for these intervenors to file their cost claims. The OEB will issue its cost awards decision after the steps outlined in the following Order section are completed.

5 ORDER

THE ONTARIO ENERGY BOARD ORDERS THAT:

1. The Tariffs of Rates and Charges set out in Schedule A of this Decision and Rate Order are approved as final effective May 1, 2021. The Tariffs of Rates and Charges will apply to electricity consumed, or estimated to have been consumed, on and after May 1, 2021. Burlington Hydro Inc. shall notify its customers of the rate changes no later than the delivery of the first bill reflecting the new final rates.

2. The Accounting Orders set out in Schedule C of this Decision and Rate Order are approved.

3. Burlington Hydro Inc. shall refile its responses to interrogatories CCC-13, 4-VECC-46(a) and DSP-DRC-4 without redactions on or before **April 29, 2021**.

4. Burlington Hydro Inc. shall refile the *Korn Ferry 2019 Management and Non-Union Employee Pay Report* and *2019 CEO Pay Review* report without redactions, with the exception of “personal information” which shall remain redacted, on or before **April 29, 2021**.

5. Burlington Hydro Inc. shall refile the *2020 MEARIE Management Salary Survey* without redactions on or before **April 29, 2021**.

6. Intervenors shall submit their cost claims to the OEB and forward a copy to Burlington Hydro Inc. by **April 20, 2021**.

7. Burlington Hydro Inc. shall file with the OEB and forward to intervenors any objections to the claimed costs by **April 27, 2021**.

8. Intervenors to which Burlington Hydro Inc. filed an objection to their claimed costs, shall file with the OEB and forward to Burlington Hydro Inc. any responses to any objections for cost claims by **May 4, 2021**.

9. Burlington Hydro Inc. shall pay the OEB’s costs incidental to this proceeding upon receipt of the OEB’s invoice.

All material filed with the OEB must quote the file number, EB-2020-0007, and be submitted in a searchable/unrestricted PDF format with a digital signature through the OEB’s web portal at https://p-pes.ontarioenergyboard.ca/PivotalUX/. Filings must clearly state the sender's name, postal address, telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the e Regulatory Electronic Submission System (RESS) Document Guidelines found at Industry | Ontario Energy Board (oeb.ca). We encourage the use of RESS; however, parties who have not yet set up an account, may email their documents to registrar@oeb.ca.

All communications should be directed to the attention of the Registrar at the address below and be received no later than 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, Shuo Zhang at Shuo.Zhang@oeb.ca and OEB Counsel, Lawren Murray at Lawren.Murray@oeb.ca .

DATED at Toronto April 15, 2021

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

SCHEDULE A

DECISION AND RATE ORDER

APPROVED 2021 TARIFF OF RATES AND CHARGES

BURLINGTON HYDRO INC.

EB-2020-0007

APRIL 15, 2021

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020--0007

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	$	28.23
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until April 30, 2023	$	(0.14)
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$	0.17
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	0.0000
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0066

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020--0007

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	$	25.32
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0168
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020--0007

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	$	68.03
Distribution Volumetric Rate	$/kW	3.3327
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until April 30, 2023	$/kW	0.0585
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kW	0.0870
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until April 30, 2023	$/kW	0.0478
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kW	0.1186
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.3799
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.5910

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020--0007

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2021

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EB-2020--0007

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	$	9.36
Distribution Volumetric Rate	$/kWh	0.0163
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0000
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	(0.0002)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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EB-2020--0007

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)	$	0.56
Distribution Volumetric Rate	$/kW	4.0390
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until April 30, 2023	$/kW	0.0577
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kW	0.0857
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until April 30, 2023	$/kW	(0.0400)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kW	4.2342
Retail Transmission Rate - Network Service Rate	$/kW	2.4700
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.8439

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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EB-2020--0007

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	$	4.55

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)

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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EB-2020--0007

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 (with the exception of wireless attachments)	$	44.50

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2021
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EB-2020--0007

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	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
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)	$	4.17
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)	$	2.08

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

SCHEDULE B

DECISION AND RATE ORDER

SETTLEMENT PROPOSAL

BURLINGTON HYDRO INC.

EB-2020-0007

APRIL 15, 2021

Burlington**hydro** inc.

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

March 17, 2021

Dear Ms. Long,

Re: Electricity Distribution License ED-2003-0004
2021 Cost of Service Application for Electricity Distribution Rates (EB-2020-0007)
Settlement Proposal

In accordance with Procedural Order No. 1, please find enclosed Burlington Hydro Inc.'s ("BHI's") Settlement Proposal and updated live Excel models as identified below.

Live Excel Models:
Settlement_Attachment_Main_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2C_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2I_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2Z_OEB_Chapter2Appendices_BHI
Settlement_Attachment_IFRS_OEB_Chapter2Appendices_BHI
Settlement_Attachment_Load_Forecast_Model_BHI
Settlement_Attachment_2021 LRAMVA Workform_BHI
Settlement_Attachment_2021_RRWF_BHI
Settlement_Attachment_2021_PILS_Workform_BHI
Settlement_Attachment_DVA_Continuity_Schedule_BHI
Settlement_Attachment_2021_Cost_Allocation_Model_BHI
Settlement_Attachment_RTSR_Workform_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

BHI is also filing its responses to the Pre-Settlement Conference Clarification Questions to supplement the evidentiary record in this proceeding.

Respectively submitted,

Sally Blackwell
Vice President, Regulatory Compliance & Asset Management
Email: sblackwell@burlingtonhydro.com

EB-2020-0007

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 May 1, 2021.

BURLINGTON HYDRO INC.

SETTLEMENT PROPOSAL

MARCH 17, 2021

Burlington Hydro Inc.
EB-2020-0007
Settlement Proposal

TABLE OF CONTENTS

APPENDICES

Appendix A: Proposed Tariff of Rates and Charges
Appendix B: Accounting Orders
Appendix C: Revenue Requirement Workform
Appendix D: PILs Workform
Appendix E: Cost Allocation Model

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_Main_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2C_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2I_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2Z_OEB_Chapter2Appendices_BHI
Settlement_Attachment_IFRS_OEB_Chapter2Appendices_BHI
Settlement_Attachment_Load_Forecast_Model_BHI
Settlement_Attachment_2021 LRAMVA Workform_BHI
Settlement_Attachment_2021_RRWF_BHI
Settlement_Attachment_2021_PILS_Workform_BHI
Settlement_Attachment_DVA_Continuity_Schedule_BHI
Settlement_Attachment_2021_Cost_Allocation_Model_BHI
Settlement_Attachment_RTSR_Workform_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Burlington Hydro Inc.
EB-2020-0007
Settlement Proposal

Filed with OEB: March 17, 2021

Burlington Hydro Inc. (the "**Applicant**" or "**BHI**") filed a Cost of Service application with the Ontario Energy Board (the "**OEB**") on October 30, 2020 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 May 1, 2021 (OEB Docket Number EB-2020-0007) (the "**Application**").

The OEB issued and published a Notice of Hearing dated November 17, 2020, and Procedural Order No. 1 on December 11, 2020, the latter of which required the parties to the proceeding to develop a proposed Issues List by February 8, 2021 and scheduled a Settlement Conference for February 22, 23, and 24, 2021.

BHI filed its Interrogatory Responses with the OEB on February 1, 2021, pursuant to which BHI updated several models and submitted them to the OEB as Excel documents. On February 8, 2021, following the Interrogatories, Ontario Energy Board staff ("**OEB Staff**") submitted a proposed Issues List as agreed to by the parties. On February 12, 2021, the OEB issued its Decision on the proposed Issues List, approving the list submitted by OEB Staff (the "**Issues List**") with the exception of one proposed issue on non-wires alternatives, which the Board ruled could be subsumed under capital investments. This Settlement Proposal is filed with the OEB in connection with the Application and is organized in accordance with the Issues List.

A Settlement Conference was convened on February 22, 2021 and continued to February 24, 2021, in accordance with the OEB's *Rules of Practice and Procedure* and the OEB's *Practice Direction on Settlement Conferences* (the "**Practice Direction**").

Andrew Pride acted as facilitator for the settlement conference which lasted for three days.

BHI and the following Intervenors (the "**Intervenors**"), participated in the settlement conference:

Consumers Council of Canada ("**CCC**")
Distributed Resource Coalition ("**DRC**")
Environmental Defence ("**ED**")
Energy Probe Research Foundation ("**EP**")
School Energy Coalition ("**SEC**")
Vulnerable Energy Consumers Coalition ("**VECC**")

BHI and the Intervenors are collectively referred to below as the "**Parties**". Notwithstanding any other clause of this Settlement Proposal, ED only takes a position on Issue 1.3, and takes no position with respect to, and does not oppose, any of the remaining issues.

OEB Staff also participated in the settlement conference. The role adopted by OEB Staff is set out in page 6 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, 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 and partially 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 and partially settled issue, as applicable, agree that the evidence in respect of that settled or partially settled issue, as applicable, 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 Intervenors have reviewed the Appendices, the Intervenors are 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 dated February 12, 2021.

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 Intervenors 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 Intervenors 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 February 12, 2021, 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 2021 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	$8,040,451	$7,586,755	($453,696)	$7,551,500	($35,255)
	Regulated Rate of Return	5.41%	5.15%	-0.26%	5.13%	-0.03%
Rate Base and Capital Expenditure	Rate Base	$148,576,805	$147,248,139	($1,328,666)	$147,285,343	$37,204
	Net Fixed Assets	$132,580,500	$132,510,062	($70,438)	$132,276,661	($233,401)
	Working Capital Base	$213,284,070	$196,507,700	($16,776,370)	$200,115,762	$3,608,062
	Working Capital Allowance	$15,996,305	$14,738,078	($1,258,228)	$15,008,682	$270,605
	2021 Test Year Capital Expenditures	$13,147,183	$13,990,133	$842,950	$13,490,133	($500,000)
Operating Expenses	Depreciation Expense	$6,883,779	$8,158,351	$1,274,572	$8,146,553	($11,798)
	Taxes/PILs (Grossed up)	$457,175	$373,140	($84,034)	$398,574	$25,433
	OM&A (Excluding Property Taxes and Other Donations)	$21,497,775	$21,497,775	$0	$20,557,775	($940,000)
	Property Taxes	$341,790	$341,790	$0	$341,790	$0
Revenue Requirement	Service Revenue Requirement	$37,220,971	$37,957,812	$736,842	$36,996,192	($961,620)
	Other Revenue	$1,691,087	$2,889,167	$1,198,080	$3,079,167	$190,000
	Base Revenue Requirement	$35,529,884	$35,068,645	($461,238)	$33,917,025	($1,151,620)
	Grossed Up Revenue Deficicency	$3,903,311	$3,410,371	($492,940)	$2,072,057	($1,338,314)

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) Sub-Total A			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$27.31	$28.26	$0.95	3.5%
Residential (10th percentile)	295		$26.90	$28.26	$1.36	5.1%
GS<50 kW	1500		$51.34	$52.17	$0.83	1.6%
GS<50 kW	2000		$59.39	$61.12	$1.73	2.9%
GS>50 kW	36700	200	$725.38	$785.25	$59.87	8.3%
Street Lighting	175	0.22	$2.07	$2.39	$0.32	15.6%
Unmetered Scattered Load	2000		$42.98	$41.56	($1.42)	(3.3%)
Class	**kWh**	**kW**	**Total Bill (after HST and OER)**			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$129.52	$131.67	$2.15	1.7%
Residential (10th percentile)	294.7		$66.19	$67.94	$1.75	2.7%
GS<50 kW	1500		$253.99	$257.03	$3.03	1.2%
GS<50 kW	2000		$330.09	$334.70	$4.62	1.4%
GS>50 kW	36700	200	$5,719.86	$5,879.63	$159.77	2.8%
Street Lighting	175	0.22	$27.24	$27.81	$0.57	2.1%
Unmetered Scattered Load	2000		$314.50	$316.22	$1.73	0.5%

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	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Actual Total Cost	$42,620,320	$45,082,250	$45,592,686	$47,890,208
Predicted Total Cost	$48,967,761	$50,673,119	$50,572,526	$51,667,559
Actual Cost Greater Than/(Less Than) Predicted Cost	($6,347,441)	($5,590,869)	($4,979,839)	($3,777,350)
Percentage Difference (Cost Performance)	**-13.9%**	**-11.7%**	**-10.4%**	**-7.6%**
Three-Year Average Performance	-12.3%	-12.5%	-12.0%	-9.9%
Stretch Factor Cohort - Annual	2	2	2	3
Stretch Factor Cohort - Annual (Three Year Average)	2	2	2	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 A for the Proposed Tariff of Rates and Charges resulting from the acceptance of this Settlement Proposal.

1.0 Planning

1.1 Capital

Is the level of planned capital expenditures appropriate and is the rationale for planning and pacing choices appropriate and adequately explained, giving due consideration to:

- *customer feedback and preferences*
- *productivity*
- *benchmarking of costs*
- *reliability and service quality*
- *impact on distribution rates*
- *trade-offs with OM&A spending*
- *government-mandated obligations*
- *the objectives of Burlington Hydro and its customers*
- *the distribution system plan*
- *the business plan*

Complete Settlement:

Opening Rate Base
The Parties agree to update BHI's 2021 Test Year opening rate base to reflect the decreased net book value of its two Incremental Capital Module ("ICM") projects as a result of applying full-year depreciation in the year the projects entered service.[1] The application of full-year depreciation is consistent with the use of full-year inputs in the ICM funding calculations for these two projects. The two ICM projects are as follows:

- ICM Project 1 – Tremaine TS CCRA
- ICM Project 2 – Tremaine TS Additional Breakers CCRA

2021 Test Year Capital Expenditures
The Parties agree to reduce BHI's 2021 Test Year Capital expenditures by $500,000 from $13,990,133 as filed in its Interrogatory Responses on February 1, 2021; resulting in 2021 Test Year capital expenditures of $13,490,133. Table 1.1A summarizes the capital expenditures by category for the 2021-2025 Distribution System Plan ("**DSP**") period.

[1] 2-Staff-33 and CQ-2-Staff-94

Table 1.1A – Summary of Capital Expenditures by Category

Category	Forecast Period (planned)				
	2021	2022	2023	2024	2025
System Access	$29,645,598	$10,905,000	$9,574,000	$8,074,000	$8,074,000
System Renewal	$2,880,000	$3,340,000	$3,065,000	$3,065,000	$3,065,000
System Service	$375,000	$800,000	$850,000	$800,000	$850,000
General Plant	$1,197,870	$2,364,500	$1,852,000	$1,169,500	$1,077,000
Total Expenditure	**$34,098,468**	**$17,409,500**	**$15,341,000**	**$13,108,500**	**$13,066,000**
Capital Contributions	($20,608,334)	($5,898,500)	($4,567,500)	($4,005,000)	($4,005,000)
Net Capital Expenditures	**$13,490,133**	**$11,511,000**	**$10,773,500**	**$9,103,500**	**$9,061,000**
System O&M	$9,387,412	$9,575,160	$9,766,663	$9,961,997	$10,161,236

Since only the 2021 Test Year expenditures are being sought for approval in this proceeding, the revised Forecast Period (2022-2025) expenditures included in Table 1.1A are bring being provided by the Applicant and are not meant to be construed as the Parties agreement that the amounts are appropriate.

Table 1.1B below identifies the changes in the 2021 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	$28,316,438	$29,645,598	$1,329,160	$29,645,598	$0
System Renewal	$2,960,000	$3,080,000	$120,000	$2,880,000	($200,000)
System Service	$375,000	$375,000	$0	$375,000	$0
General Plant	$1,552,000	$1,497,870	($54,130)	$1,197,870	($300,000)
Total Expenditure	**$33,203,438**	**$34,598,468**	**$1,395,030**	**$34,098,468**	**($500,000)**
Capital Contributions	($20,056,254)	($20,608,334)	($552,080)	($20,608,334)	$0
Net Capital Expenditures	**$13,147,183**	**$13,990,133**	**$842,950**	**$13,490,133**	**($500,000)**

BHI's total 2021 net capital expenditures are the same as its 2021 net capital additions.

Capital Variance Accounts

BHI's increase in its 2021 capital expenditure is primarily driven by two separate large System Access projects (the Dundas Street Road Widening Project and the Waterdown Rd Road Widening Project) that it is required to undertake. Since these two projects are driven by a third-party and there is an inherent level of uncertainty with respect to both their scope and whether they will be completed in the test year, the Parties agree, for the purposes of settlement, to establish two separate asymmetrical capital variance accounts to track the revenue requirement associated with the difference between the budgeted and actual net capital additions in the 2021 Test Year and the resulting impact through the IRM period. The mechanics of these accounts are discussed under Issue 4.2(k).

Reactive vs. Proactive Asset Replacement

To better assess BHI's capital plan in a future application, the Parties agree that BHI will commence tracking reactive capital expenditures separately from proactive capital expenditures for its programs and projects as identified in Table 1.1C below. The tracking will include quantity (e.g., # of wood poles replaced) and total expenditures for both reactive and proactive replacements.

Table 1.1C – Reactive vs. Proactive Asset Replacement

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

DSP Metrics

The parties agree that BHI will introduce five new metrics (and corresponding targets) to track the progress of its DSP, as identified in Table 1.1D below. BHI will report its actual performance against these five metrics for each year over the 2021-2025 period as part of its next rebasing application.

Table 1.1D – DSP Metrics

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

The Parties agree that the revised capital expenditures and additions, in conjunction with the asymmetrical capital variance accounts identified above, are reasonable. The Applicant confirms that this level of spending is sufficient to maintain a safe and reliable distribution system.

Evidence:

Application:
Exhibit 1 Sections 1.2, 1.3, 1.5, 1.6, 1.7, 1.8
Exhibit 2, inclusive of Appendix A (DSP)

IRs:
1-Staff-2, 1-Staff-3, 1-Staff-4, 1-Staff-5, 1-Staff-6, 1-Staff-7, 2-Staff-9, 2-Staff-10, 2-Staff-11, 2-Staff-12, 2-Staff-13, 2-Staff-15, 2-Staff-16, 2-Staff-17, 2-Staff-18, 2-Staff-19, 2-Staff-20, 2-Staff-21, 2-Staff-22, 2-Staff-23, 2-Staff-24, 2-Staff-25, 2-Staff-26, 2-Staff-27, 2-Staff-28, 2-Staff-29, 2-Staff-30, CCC-3, CCC-6, CCC-10, CCC-11, CCC-13, CCC-14, CCC-15, CCC-16, DRC-1, DRC-2, DSP-DRC-3, DSP-DRC-4, 1-DRC-5, ED-9, ED-10, ED-11, ED-12, ED-13, ED-14, ED-15, ED-16, ED-17, ED-18, ED-19, 1-SEC-1, 1-SEC-2, 1-SEC-3, 1-SEC-4, 1-SEC-5, 1-SEC-8, 1-SEC-9, 1-SEC-10, 2-SEC-11, 2-SEC-12, 2-SEC-14, 2-SEC-15, 2-SEC-16, 2-SEC-17, 2-SEC-18, 2-SEC-19, 2-SEC-20, 1.0-VECC-2, 2.0-VECC-4, 2.0-VECC-5, 2.0-VECC-6, 2.0-VECC-7, 2.0-VECC-8, 2.0-VECC-9, 2.0-VECC-10, 2.0-VECC-11, 2.0-VECC-12, 2.0-VECC-13, 2.0-VECC-14, 2.0-VECC-15, 2.0-VECC-16, 2.0-VECC-17, 2.0-VECC-18, 2.0-VECC-19, 2.0-VECC-20, 2.0-VECC-21, 2.0-VECC-22, 2.0-VECC-23, 2.0-VECC-24, 2.0-VECC-25, 2.0-VECC-26, 2.0-VECC-27, 4.0-VECC-59, 4.0-VECC-60, 4.0-VECC-64

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_Main_OEB_Chapter2Appendices_BHI

Clarifying Question Responses:
CQ-2-Staff-83, CQ-2-Staff-84, CQ-2-Staff-85, CQ-2-Staff-86, CQ-2-Staff-87, CQ-2-Staff-94, CQ-1-SEC-1, CQ-2-VECC-85, CQ-2-VECC-86, CQ-2-VECC-87, CQ-2-VECC-88, CQ-2-VECC-89

Supporting Parties: All
Parties Taking No Position: ED

1.2 OM&A

Is the level of planned OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained, giving due consideration to:

- customer feedback and preferences
- productivity
- benchmarking of costs
- reliability and service quality
- impact on distribution rates
- trade-offs with capital spending
- government-mandated obligations
- the objectives of Burlington Hydro and its customers
- the distribution system plan
- the Business Plan

Complete Settlement:
For the purposes of settlement, the parties agree to reduce BHI's 2021 Test Year OM&A before Property Taxes by $940,000 from $21,497,775 to $20,557,775. Table 1.2A identifies the changes in OM&A expenses as compared to that which was filed in BHI's original Application.

The Parties acknowledge that there is bad debt expense of $200,000 included in the proposed 2021 Test Year OM&A of $20,557,775.

The Parties agree that based on the revised level of OM&A expenditures, BHI's rationale for planning choices is appropriate and adequately explained.

Table 1.2A – Summary of OM&A Expenses -Variance

Description	2014 Actuals (MIFRS)	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Operations	$5,778,866	$4,261,688	$4,261,688	$0	$3,850,665	($411,022)
Maintenance	$2,609,624	$6,004,924	$6,004,924	$0	$5,536,747	($468,178)
Sub-Total	**$8,388,490**	**$10,266,612**	**$10,266,612**	**$0**	**$9,387,412**	**($879,200)**
Billing and Collecting	$2,356,794	$2,999,028	$2,999,028	$0	$2,999,028	$0
Community Relations	$10,205	$36,800	$36,800	$0	$36,800	$0
Administration and General	$6,091,051	$8,195,335	$8,195,335	$0	$8,134,535	($60,800)
Sub-Total	**$8,458,050**	**$11,231,164**	**$11,231,164**	**$0**	**$11,170,364**	**($60,800)**
Total 2-JA	**$16,846,540**	**$21,497,775**	**$21,497,775**	**$0**	**$20,557,775**	**($940,000)**

Evidence:

Application:
Exhibit 1 Sections 1.2, 1.3, 1.5, 1.6, 1.7, 1.8
Exhibit 4

IRs:
1-Staff-2, 1-Staff-3, 1-Staff-4, 1-Staff-5, 1-Staff-6, 1-Staff-7, 2-Staff-12, 2-Staff-14, 2-Staff-19, 2-Staff-23, 4-Staff-41, 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-55, CCC-4, CCC-6, CCC-8, CCC-10, CCC-12, CCC-14, CCC-20, CCC-21, CCC-22, CCC-23, CCC-24, CCC-25, CCC-26, CCC-27, CCC-28, DRC-1, DRC-2, DSP-DRC-3, DSP-DRC-4, 1-DRC-5, EP-2, EP-4, EP-5, EP-6, EP-8, EP-9, EP-13, EP-15, EP-16, EP-17, 1-SEC-1, 1-SEC-2, 1-SEC-3, 1-SEC-4, 1-SEC-5, 4-SEC-25, 4-SEC-26, 4-SEC-27, 4-SEC-28, 4-SEC-29, 4-SEC-30, 4-SEC-31, 4-SEC-32, 4-SEC-33, 1.0-VECC-2, 4.0-VECC-44, 4.0-VECC-45, 4.0-VECC-46, 4.0-VECC-47, 4.0-VECC-48, 4.0-VECC-49, 4.0-VECC-50, 4.0-VECC-51, 4.0-VECC-52, 4.0-VECC-53, 4.0-VECC-54, 4.0-VECC-55, 4.0-VECC-56, 4.0-VECC-57, 4.0-VECC-58, 4.0-VECC-59, 4.0-VECC-60, 4.0-VECC-61, 4-VECC-62, 4-VECC-63, 4.0-VECC-64

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_Main_OEB_Chapter2Appendices_BHI

Clarifying Question Responses:
CQ-2-Staff-86, CQ-1-Staff-92, CQ-1-SEC-1, CQ-4-SEC-2, CQ-2-VECC-85, CQ-2-VECC-87, CQ-2-VECC-88, CQ-4-VECC-90, CQ-4-VECC-91

Supporting Parties: All
Parties Taking No Position: ED

1.3 Has Burlington Hydro appropriately considered measures to cost-effectively reduce distribution losses in its planning processes and included such measures where appropriate?

Complete Settlement:
The parties agree that between 2021 and 2025, BHI shall make best efforts to target its five-year average total system losses at the target of 3.4% through cost-effective measures subject to variation in distribution losses due to factors outside of BHI's control.[2] In addition, over the course of 2021-2022, BHI shall prepare a plan to reduce distribution losses as much as possible through cost-effective measures. The utility shall file the plan with the OEB when complete. In 2022-2025, BHI shall implement as many of the cost-effective measures set out in its plan as possible (e.g., any changes to planning and procurement processes to better mitigate losses, investments that can be made within current budgets, operational measures, etc.). All other cost-effective measures will be incorporated into the utility's next rebasing application and DSP.

Evidence:

Application:
Exhibit 8 Section 8.9
DSP Appendix 1 (Material Investment Summary Documents)

IRs:
ED-1, ED-2, ED-3, ED-4, ED-5, ED-6, ED-7

Appendices to this Settlement Proposal:
None

Settlement Models:
None

Clarifying Question Responses:
None

Supporting Parties: All
Parties Taking No Position: None

[2] For further clarity, this includes losses in the distributor's system and transmission losses upstream of the distributor.

2.0 Revenue Requirement

2.1 Are all elements of the revenue requirement reasonable, and have they been appropriately determined in accordance with OEB policies and practices?

Complete Settlement:
The Parties agree that all elements of the Revenue Requirement are reasonable and have been correctly determined in accordance with OEB policies and practices. Specifically:

a) *Rate Base:* Subject to the adjustments expressly identified in this Settlement Proposal, the parties accept that the rate base calculations are reasonable and have been correctly determined in accordance with OEB policies and practices.
b) *Working Capital:* The Parties agree to the Working Capital filed in this Settlement Proposal which has been adjusted from the Working Capital filed in BHI's interrogatory responses for the following:
   i. Revised Cost of Power as a result of changes in the Load Forecast; and
   ii. Revised OM&A as a result of a proposed envelope reduction of $940,000 as identified in Table 1.2A.
c) *Cost of Capital:* The Parties agree to adjust the long-term debt rate on the $5M credit facility with the TD bank from 2.85%, as filed in BHI's interrogatory responses, to 2.227%, which reflects the current lower level of interest rates based on market information. This adjustment results in a reduction in the long-term debt rate from 3.12% to 3.07%; and a reduction in the weighted average cost of capital from 5.15% to 5.13%. Subject to this adjustment, the parties agree that the proposed capital structure, rate of return on equity, and short-term and long-term debt rates are determined in accordance with OEB policy and reflect the most recent cost of capital parameters published by the OEB on November 9, 2020.[3]
d) *Other Revenue:* For the purposes of settlement, the Parties agree to increase Other Revenue by $190,000 as compared to that which was filed in BHI's interrogatory responses, and as identified in Table A of this Settlement Proposal.
e) *Depreciation:* Subject to the adjustments to rate base as identified herein, the Parties accept the evidence of BHI that its forecast depreciation/amortization expenses are appropriate, reflect the useful lives of BHI's assets, and have been correctly determined in accordance with OEB accounting policies and practices.
f) *PILs:* The Parties agree to use the unsmoothed approach to account for the difference in revenue requirement as result of the implementation of the Accelerated Investment Incentive Plan ("AIIP") in 2018. Specifically, the Parties agree that BHI will not increase PILs expense in the 2021 Test Year to account for the phasing out period of the AIIP in 2024 and 2025; and BHI will use the Account 1592 sub-account CCA Changes

[3] Cost of Capital Parameter Updates | Ontario Energy Board (oeb.ca)

to track the revenue requirement impacts during the phasing out period of the AIIP. The balance in this sub-account is to be disposed of at BHI's next rebasing application. Parties agree that the PILs calculations, as updated to incorporate the changes identified in this Settlement Proposal, have been appropriately determined in accordance with OEB policies and practices.

Evidence:

Application:
Exhibit 1 Section 1.6 A
Exhibit 2 Section 2.1
Exhibit 3 Section 3.3
Exhibit 4 Sections 4.2, 4.4, 4.5
Exhibit 5
Exhibit 6

IRs:
1-Staff-1, 2-Staff-14, 2-Staff-31, 2-Staff-34, 3-Staff-40, 4-Staff-60, 4-Staff-61, 5-Staff-63, CCC-7, CCC-15, CCC-18, CCC-19, EP-2, EP-8, EP-12, EP-18, 2-SEC-13, 3-SEC-24, 5-SEC-34, 1.0-VECC-1, 3.0-VECC-42

Appendices to this Settlement Proposal:
Appendix C – Revenue Requirement Workform
Appendix D – PILS Workform

Settlement Models:
Settlement_Attachment_Main_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2C_OEB_Chapter2Appendices_BHI
Settlement_Attachment_2021_RRWF_BHI
Settlement_Attachment_2021_PILS_Workform_BHI

Clarifying Question Responses:
CQ-1-Staff-92, CQ-4-Staff-95, CQ-5-SEC-3, CQ-3-VECC-80

Supporting Parties: All
Parties Taking No Position: ED

2.2 Has the revenue requirement been accurately determined based on these elements?

Complete Settlement:

The Parties agree that the revenue requirement has been accurately determined based on the elements identified in Issue 2.1. The elements of Revenue Requirement are identified in Tables 2.2A to 2.2H below.

Table 2.2A – 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)	$21,450,775	$21,450,775	$0	$20,510,775	($940,000)
Property Taxes	$341,790	$341,790	$0	$341,790	$0
LEAP	$47,000	$47,000	$0	$47,000	$0
Depreciation and Amortization	$6,883,779	$8,158,351	$1,274,572	$8,146,553	($11,798)
Total	**$28,723,345**	**$29,997,917**	**$1,274,572**	**$29,046,118**	**($951,798)**
Regulated Return on Capital	$8,040,451	$7,586,755	($453,696)	$7,551,500	($35,255)
Income Taxes Grossed Up	$457,175	$373,140	($84,034)	$398,574	$25,433
Service Revenue Requirement	**$37,220,971**	**$37,957,812**	**$736,842**	**$36,996,192**	**($961,620)**
Other Revenues	$1,691,087	$2,889,167	$1,198,080	$3,079,167	$190,000
Base Revenue Requirement	**$35,529,884**	**$35,068,645**	**($461,238)**	**$33,917,025**	**($1,151,620)**
Distribution Revenue at Current Rates	$31,626,573	$31,658,275	$31,702	$31,844,968	$186,693
Grossed Up Revenue Deficiency	**$3,903,311**	**$3,410,371**	**($492,940)**	**$2,072,057**	**($1,338,314)**

Table 2.2B – Rate Base

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Average Gross Capital	$309,790,789	$309,786,105	($4,685)	$309,536,105	($250,000)
Average Accumulated Depreciation	$177,210,289	$177,276,043	$65,754	$177,259,444	($16,599)
Average Net Book Value	**$132,580,500**	**$132,510,062**	**($70,438)**	**$132,276,661**	**($233,401)**
Working Capital Base	$213,284,070	$196,507,700	($16,776,370)	$200,115,762	$3,608,062
Working Capital Allowance (%)	7.50%	7.50%	0.00%	7.50%	0.00%
Working Capital Allowance ($)	**$15,996,305**	**$14,738,078**	**($1,258,228)**	**$15,008,682**	**$270,605**
Rate Base	**$148,576,805**	**$147,248,139**	**($1,328,666)**	**$147,285,343**	**$37,204**

Table 2.2C – Cost of Power

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Power Purchased	$125,906,235	$104,299,992	($21,606,243)	$104,672,331	$372,339
Global Adjustment	$78,174,252	$63,472,650	($14,701,601)	$65,241,290	$1,768,640
Wholesale Market Service Charge	$6,157,042	$6,145,698	($11,344)	$6,225,186	$79,488
Transmission - Network	$11,627,634	$11,606,054	($21,580)	$14,013,242	$2,407,188
Transmission - Connection	$10,593,232	$10,572,288	($20,944)	$10,715,253	$142,965
Smart Meter Entity Charge	$462,521	$462,521	$0	$462,521	$0
Ontario Electricty Rebate	($41,476,411)	($21,891,068)	$19,585,343	($22,113,627)	($222,558)
Total	**$191,444,505**	**$174,668,135**	**($16,776,370)**	**$179,216,197**	**$4,548,062**

Table 2.2D – Working Capital Allowance

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Total Distribution Expenses	$21,839,565	$21,839,565	$0	$20,899,565	($940,000)
Power Supply Expenses	$191,444,505	$174,668,135	($16,776,370)	$179,216,197	$4,548,062
Total Expenses for Working Capital	**$213,284,070**	**$196,507,700**	**($16,776,370)**	**$200,115,762**	**$3,608,062**
Working Capital Allowance %	7.50%	7.50%	0.00%	7.50%	0.00%
Total Working Capital Allowance	**$15,996,305**	**$14,738,078**	**($1,258,228)**	**$15,008,682**	**$270,605**

Table 2.2E – Capital Structure and Cost of Capital

Description	Capitalization Ratios		Rate	Return
	%	$	%	$
Debt				
Long-term Debt	56.0%	$82,479,792	3.07%	$2,534,961
Short-term Debt	4.0%	$5,891,414	1.75%	$103,100
Total Debt	**60.0%**	**$88,371,206**	**2.99%**	**$2,638,061**
Equity				
Common Equity	40.0%	$58,914,137	8.34%	$4,913,439
Preferred Shares	0.0%	$0	0.00%	$0
Total Equity	**40.0%**	**$58,914,137**	**8.34%**	**$4,913,439**
Total	**100.0%**	**$147,285,343**	**5.13%**	**$7,551,500**

Table 2.2F – Depreciation Expense

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Depreciation Expense	$6,883,779	$8,158,351	$1,274,572	$8,146,553	($11,798)

Table 2.2G – PILs

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Taxes/PILs (Grossed up)	$457,175	$373,140	($84,034)	$398,574	$25,433

Table 2.2H – Other Revenue

Description	Application	Interrogatories	Variance	Settlement	Variance
	a	b	c = b-a	d	e = d-b
Specific Service Charges	$416,360	$416,360	$0	$416,360	$0
Late Payment Charges	$294,000	$294,000	$0	$294,000	$0
Other Operating Revenues	$699,677	$1,897,757	$1,198,080	$1,897,757	$0
Other Income or Deductions	$281,050	$281,050	$0	$471,050	$190,000
Total	**$1,691,087**	**$2,889,167**	**$1,198,080**	**$3,079,167**	**$190,000**

Evidence:

Application:
Exhibit 6

IRs:
1-Staff-1

Appendices to this Settlement Proposal:
Appendix C – Revenue Requirement Workform

Settlement Models:
Settlement_Attachment_2021_RRWF_BHI

Clarifying Question Responses:
None

Supporting Parties: All
Parties Taking No Position: ED

3.0 Load Forecast, Cost Allocation and Rate Design

3.1 Are the proposed load and customer forecast, loss factors, conservation and demand management adjustments and resulting billing determinants appropriate, and, to the extent applicable, are they an appropriate reflection of the energy and demand requirements of Burlington Hydro's customers?

Complete Settlement:
The Parties agree that the proposed load and customer forecast, loss factors, conservation and demand management adjustments and resulting billing determinants in this Settlement Proposal are appropriate, and, to the extent applicable, are an appropriate reflection of the energy and demand requirements of BHI's customers. Specifically, the Parties agree to the following adjustments as compared to that which was filed in the Application on October 30, 2020:

- Total class consumption is used as the dependent variable instead of consumption per customer per day for each of the Residential, GS<50 kW and GS>50 kW[4]. This results in an improved R-squared value and is more consistent with the approach used in BHI's previous Cost of Service application[5];
- Number of days in the month are used as independent variables for each of the Residential, GS<50 kW and GS>50 kW classes[6];
- Customer counts are used as independent variable for the GS<50 kW and GS>50 kW rate classes[7];
- CDM data and the GS>50 February 2020 customer counts are updated[8];
- Most current economic forecast (post-COVID as of January 21, 2021) is incorporated for the GS<50 kW and the GS>50 kW rate classes[9]; and
- pre-COVID economic forecast (February 2020) is used to determine the residential load forecast[10] as the Applicant expects this to be more representative of residential consumption over the five-year IRM term.

The resulting load forecast and customer counts are identified below in Tables 3.1A and 3.1B respectively.

[4] 3-Staff-36
[5] EB-2013-0115
[6] 3-Staff-36
[7] 3-Staff-36, 3-Staff-89
[8] CQ-VECC-79a
[9] 3-Staff-37h
[10] 3-VECC-31c

Since the agreed 2021 Test Year load forecast was derived from models that included economic forecasts created after the beginning of the COVID-19 Emergency, the Parties agree that BHI shall not be allowed to include any lost revenue because of lower load due to COVID-19 in Account 1509 - Impacts Arising from the COVID-19 Emergency, Sub-account Lost Revenues, or any other sub-account, beginning May 1, 2021. See Issue 4.2(j).

Table 3.1A – Load Forecast

Rate Class	Application		Interrogatories		Settlement	
	kWh	kW	kWh	kW	kWh	kW
Residential	529,231,270		524,243,173		520,340,552	
GS<50 kW	167,003,174		169,189,510		168,693,830	
GS>50 kW	825,433,794	2,267,945	825,433,794	2,267,945	849,749,403	2,334,671
Streetlighting	5,569,644	15,528	5,569,644	15,528	5,569,644	15,528
Unmetered Scattered Load	3,103,371		3,103,371		3,103,371	
Total	**1,530,341,252**	**2,283,473**	**1,527,539,492**	**2,283,473**	**1,547,456,800**	**2,350,199**

Table 3.1B – Customer Forecast (Annual Average)

Rate Class	Determinant	Application	Interrogatories	Settlement
Residential	Customers	62,056	62,056	62,056
GS<50 kW	Customers	5,564	5,564	5,564
GS>50 kW	Customers	1,003	1,003	1,004
Streetlighting	Connections	17,283	17,283	17,283
Unmetered Scattered Load	Connections	554	554	554

The Parties agree to the CDM adjustment to the load forecast as identified in Table 3.1C below[11]. This adjustment represents full-year savings from CDM programs implemented in 2020 and the CDM savings to be used as the basis for the LRAMVA threshold.

Table 3.1C – CDM Adjustment and LRAMVA Threshold Values

Rate Class	Application		Interrogatories		Settlement	
	kWh	kW	kWh	kW	kWh	kW
GS<50 kW	597,270		597,270		122,604	
GS>50 kW	6,157,956	16,796	6,157,956	16,796	2,192,934	5,981
Total	**6,755,225**	**16,796**	**6,755,225**	**16,796**	**2,315,538**	**5,981**

The Parties agree that the proposed loss factor for the 2021 Test Year is appropriate as identified in Tables 3.1D and 3.1 E below; however, BHI shall make best efforts to target its five-year average total system losses at the target of 3.4% through cost-effective measures as identified under Issue 1.3 in this Settlement Proposal.

[11] CQ-3-Staff-88 and CQ-3-VECC 79 b)

Table 3.1D – OEB Appendix 2-R

	Description	Historical Years					5-Year Average
		2015	2016	2017	2018	2019	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,673,683,827	1,699,863,833	1,615,885,086	1,660,114,823	1,595,966,604	1,649,102,835
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,668,538,850	1,694,806,677	1,611,122,908	1,655,201,680	1,590,583,033	1,644,050,629
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = A(2) - B	1,668,538,850	1,694,806,677	1,611,122,908	1,655,201,680	1,590,583,033	1,644,050,629
D	"Retail" kWh delivered by distributor	1,616,124,204	1,641,753,762	1,557,033,292	1,596,763,923	1,530,473,908	1,588,429,818
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = D - E	1,616,124,204	1,641,753,762	1,557,033,292	1,596,763,923	1,530,473,908	1,588,429,818
G	Loss Factor in Distributor's system = C / F	1.0324	1.0323	1.0347	1.0366	1.0393	1.0350
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0031	1.0030	1.0030	1.0030	1.0034	1.0031
	Total Losses						
I	Total Loss Factor = G x H	1.0356	1.0354	1.0378	1.0397	1.0428	1.0382

Table 3.1E – Total Loss Factors

Customer	Distribution Loss Factor	SFLF	Total Loss Factor
Secondary Metered Customer <5,000kW	1.0350	1.0031	1.0382
Primary Metered Customer <5,000kW	1.0248	1.0031	1.0279

Evidence:

Application:
Exhibit 1 Section 1.6 C
Exhibit 3 Sections 3.1, 3.2
Exhibit 4 Section 4.6
Exhibit 8 Section 8.9

IRs:
3-Staff-35, 3-Staff-36, 3-Staff-37, 3-Staff-38, 3-Staff-39, 7-Staff-64, CCC-10, CCC-17, DRC-1, DRC-2, DSP-DRC-3, ED-1, ED-2, ED-3, ED-4, ED-5, ED-6, ED-7, ED-13, ED-14, ED-15, ED-16, ED-17, ED-18, ED-19, EP-3, EP-4, EP-11, EP-17, 1-SEC-5, 3-SEC-21, 3-SEC-22, 3-SEC-23, 3.0-VECC-28, 3.0-VECC-29, 3.0-VECC-30, 3.0-VECC-31, 3.0-VECC-32, 3.0-VECC-33, 3.0-VECC-34, 3.0-VECC-35, 3.0-VECC-36, 3.0-VECC-37, 3.0-VECC-38, 3.0-VECC-39, 3.0-VECC-40, 3.0-VECC-41

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_Load_Forecast_Model_BHI

Clarifying Question Responses:
CQ-3-Staff-88, CQ-3-Staff-89, CQ-3-Staff-90, CQ-3-VECC-77, CQ-3-VECC-78, CQ-3-VECC-79

Supporting Parties: All
Parties Taking No Position: ED

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

Complete Settlement:
The Parties accept the proposed cost allocation methodology, allocations, and revenue-to-cost ratios as filed in this Settlement Proposal as follows.

a) *Cost Allocation Methodology and Allocations:* The Parties agree with the cost allocation methodology as filed in this Settlement Proposal and accept the results of the cost allocation. The Parties agree to the weighting factors identified in Table 3.2A below. The Billing and Collecting weighting factors in this proposal incorporate 2021 Test Year costs as compared to the original Application which used historical actual costs.[12] The Services weighting factors in this proposal are based on installed cost (paid by BHI) as compared to the weighting factors in the original Application which were based on gross cost.[13]

Table 3.2A – Weighting Factors

Billing and Collecting	Residential	GS<50 kW	GS>50 kW	Streetlighting	Unmetered Scattered Load
Application	1.00	1.62	10.82	0.61	0.82
Settlement	1.00	1.58	10.30	0.61	0.83
Services	**Residential**	**GS<50 kW**	**GS>50 kW**	**Streetlighting**	**Unmetered Scattered Load**
Application	1.00	2.18	0.00	0.03	0.30
Settlement	1.00	0.50	0.00	0.09	0.96

b) Load Profiles: BHI updated the load profiles for all rate classes in this Application. Load profiles were derived using weather-normalized 2018 hourly load data; and adjustments were made to align the 2018 load profiles with the proposed 2021 Load Forecast. In its previous rate rebasing application BHI used the load profiles provided by Hydro One which were based on 2004 data. Consumption patterns have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing.

The Parties agree the cost allocation methodology and the allocations and revenue to cost ratios reflect OEB policies and are appropriate for purposes of settlement. However, in terms of the load profiles used, while Parties agree to accept the demand allocators

[12] CQ-7-VECC-83
[13] 7-Staff-65

proposed by BHI for purposes of settlement as they are reasonable, there is no agreement that the methodology used to derive the values is appropriate.

c) *Revenue to Cost Ratios:* The Parties agree to adjust the revenue-to-cost ratios of the 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 3.2B below.

Table 3.2B – Revenue-to-Cost Ratios

Rate Class	R:C Ratios from Cost Allocaiton 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	118.51%	118.51%	80%	120%
GS>50 kW	93.83%	94.42%	80%	120%
Streetlighting	146.56%	120.00%	80%	120%
USL	132.06%	120.00%	80%	120%

Evidence:

Application:
Exhibit 1 Section 1.6 G
Exhibit 7

IRs:
7-Staff-65, 7-Staff-66, 7-Staff-67, 7-Staff-68, ED-13, 7.0-VECC-65, 7.0-VECC-66, 7.0-VECC-67, 7.0-VECC-68, 7.0-VECC-69, 7.0-VECC-70, 7.0-VECC-71, 7.0-VECC-72 7.0-VECC-73, 7.0-VECC-x, 7.0-VECC-74

Appendices to this Settlement Proposal:
Appendix E – Cost Allocation Model

Settlement Models:
Settlement_Attachment_2021_Cost_Allocation_Model_BHI

Clarifying Question Responses:
CQ-7-Staff-91, CQ-7-VECC-82, CQ-7-VECC-83

Supporting Parties: All
Parties Taking No Position: ED

3.3 Are Burlington Hydro's proposals, including the proposed fixed/variable splits, for rate design appropriate?

Complete Settlement:
Subject to the adjustments expressly identified in this Settlement Proposal, the Parties agree that BHI's proposals, including the proposed fixed/variable splits, for rate design are appropriate.

BHI agrees to adjust its rate design proposal for the GS<50 kW rate class such that the 2021 Test Year service charge (fixed distribution rate) shall not exceed the Minimum System with PLCC adjustment of $25.32 as identified on Tab "O2 Fixed Charge/Floor/Ceiling" in the Cost Allocation Model filed as part of this Settlement Proposal. Table 3.3A below identifies the proposed distribution revenue charges.

Table 3.3A – Proposed Fixed/Variable Distribution Charges

Rate Class	Unit	2020 Distribution Rates Application	2021 Distribution Rates Application	2021 Distribution Rates Interrogatories	Variance	2021 Distribution Rates Settlement	Variance	Fixed / Variable Split
			a	b	c = b-a	d	e = d-b	
Residential								
Monthly Service Charge	$	26.51	29.78	29.42	- 0.36	28.23	- 1.19	100.0%
Volumetric Charge	$/kWh	-	-	-	-	-	-	0.0%
Min. System with PLCC Adj.	$					18.74		
GS<50 kW								
Monthly Service Charge	$	27.06	30.40	29.98	- 0.42	25.32	- 4.66	37.3%
Volumetric Charge	$/kWh	0.0145	0.0163	0.0161	- 0.0002	0.0168	0.0007	62.7%
Min. System with PLCC Adj.	$					25.32		
GS>50 kW								
Monthly Service Charge	$	63.44	72.13	70.40	- 1.73	68.03	- 2.37	10.2%
Volumetric Charge	$/kW	3.1231	3.5199	3.4408	- 0.0791	3.3327	- 0.1081	89.8%
Min. System with PLCC Adj.	$					95.84		
Streetlighting								
Monthly Service Charge	$	0.65	0.56	0.59	0.03	0.56	- 0.03	64.9%
Volumetric Charge	$/kW	4.7037	4.0616	4.2525	0.1909	4.0390	- 0.2135	35.1%
Min. System with PLCC Adj.	$					4.17		
USL								
Monthly Service Charge	$	9.73	7.14	9.83	2.69	9.36	- 0.47	55.2%
Volumetric Charge	$/kWh	0.0169	0.0124	0.0171	0.0047	0.0163	- 0.0008	44.8%
Min. System with PLCC Adj.	$					11.77		

Evidence:

Application:
Exhibit 1 Sections 1.6 G
Exhibit 8 Sections 8.0, 8.1, 8.13, 8.2

IRs:
ED-8

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_2021_RRWF_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Clarifying Question Responses:
CQ-8-VECC-84

Supporting Parties: All
Parties Taking No Position: ED

3.4 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 3.4A below. The Network Service Rates were changed in this proposal, as compared to BHI's original Application, to incorporate the most up-to-date Uniform Transmission Rates.[14] There was no change to the combined Line and Transformation Connection Service Rate.

Table 3.4A – Retail Transmission Service Rates

Proposed 2021 RTSR Network Service Rate						
Rate Class	Unit	Application	Interrogatories	Variance	Settlement	Variance
		a	b	c = b-a	d	e = d-b
Residential	kWh	0.0072	0.0072	-	0.0086	0.0014
GS<50 kW	kWh	0.0069	0.0069	-	0.0082	0.0013
GS>50 kW	kW	2.8371	2.8371	-	3.3799	0.5428
Streetlighting	kW	2.0733	2.0733	-	2.4700	0.3967
USL	kWh	0.0069	0.0069	-	0.0082	0.0013

Proposed 2021 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	0.0066	0.0066	-	0.0066	-
GS<50 kW	kWh	0.0059	0.0059	-	0.0059	-
GS>50 kW	kW	2.5910	2.5910	-	2.5910	-
Streetlighting	kW	1.8439	1.8439	-	1.8439	-
USL	kWh	0.0059	0.0059	-	0.0059	-

Evidence:
Application:
Exhibit 8 Section 8.3, Appendix A

IRs:
8-Staff-69, 8.0-VECC-75

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_RTSR_Workform_BHI
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

[14] EB-2020-0251, December 17, 2020

Clarifying Question Responses:
None

Supporting Parties: All
Parties Taking No Position: ED

3.5 Are the Specific Service Charges, Retail Service Charges, and Pole Attachment 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 A – Proposed Tariff of Rates and Charges, are appropriate. Appendix A specifically incorporates the following:

- There is no change to the specific service charges proposed in BHI's Application filed October 30, 2020 with the exception of the Pole Attachment Charges;
- The energy retailer service charges have been updated to incorporate an inflationary adjustment of 2.2% effective January, 2021[15]; and
- The parties agree for the purposes of settlement not to include a separate tariff on BHI's Proposed Tariff of Rates and Charges for wireline pole attachments for non-carriers. The specific service charge for wireline pole attachments on the Proposed Tariff of Rates and Charges attached as Appendix A to this Settlement Proposal is the OEB's 2021 approved rate for carriers. [16]

Evidence:
Application:
Exhibit 8 Sections 8.4, 8.5, 8.6, 8.7, 8.8, 8.9, 8.10

IRs:
3-Staff-40, 8-Staff-70, 8-Staff-71, 9-Staff-74, 3.0-VECC-42, 8.0-VECC-76

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI

Clarifying Question Responses:
CQ-3-VECC-80

Supporting Parties: All
Parties Taking No Position: ED

[15] EB-2020-0285, December 3, 2020, p 1
[16] EB-2020-0288, December 10, 2020

4.0 Accounting

4.1 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 any changes in accounting standards, policies, estimates and adjustments have been properly identified and recorded, and the rate-making treatment of each of these impacts is appropriate.

Evidence:

Application:
Exhibit 1 Sections 1.4.12, 1.4.13, 1.6 B, 1.9.8, 1.9.9
Exhibit 2 Sections 2.2.5, 2.26
Exhibit 4 Sections 4.1.5, 4.1.6, 4.4.4, 4.5
Exhibit 6 Section 6.3.1

IRs:
1-Staff-6, 1-Staff-8, 4-Staff-62, 4-SEC-26, 9-SEC-35, 9-SEC-36

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_2021_RRWF_BHI

Clarifying Question Responses:
CQ-2-Staff-93, CQ-2-Staff-94, CQ-4-Staff-95, CQ-9-Staff-96, CQ-9-Staff-98, CQ-9-Staff-99, CQ-3-VECC-81

Supporting Parties: All
Parties Taking No Position: ED

4.2 Are Burlington Hydro'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:

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 4.2A below. 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 October 30, 2020 are appropriate and agree that BHI dispose of its Group 1 DVAs on an interim basis as at December 2019, including interest to April 30, 2021.

b) *Group 2 DVAs – Monthly Billing Incremental Costs:* BHI is seeking recovery of the incremental costs associated with the transition to monthly billing in BHI's service territory. The Parties agree that the incremental costs associated with the transition to monthly billing (e.g. postage, mail service, stationery, software) should be offset by a cash flow benefit.

For the purposes of settlement, the Parties agree that this cash flow benefit should be based on the difference between the working capital allowance which was built into rates in BHI's 2014 Cost of Service and that which would have been calculated had monthly billing been in effect. This resulting balance in the account and the associated working capital allowance calculation are identified in Tables 4.2A and 4.2B below, respectively.

The Parties agree to forecast and dispose of the balance in the account up to April 30, 2021 so that the account can be discontinued effective May 1, 2021.

Table 4.2A – Monthly Billing Incremental Costs

DR/(CR)	2017	2018	2019	2020 Bridge Year	2021 Test Year [1]	Total
Postage/Mail Service/Stationery Costs	$339,341	$256,409	$238,819	$251,555	$83,392	$1,169,516
Working Capital Allowance Savings [2]	($173,488)	($173,488)	($173,488)	($173,488)	($57,829)	($751,781)
Revenue Requirement			$70,073	$42,213	$13,345	$125,631
Sub-Total to be Recovered from Customers	**$165,853**	**$82,921**	**$135,404**	**$120,280**	**$38,908**	**$543,365**
Carrying Charges	$607	$3,949	$7,117	$5,629	$973	$18,274
Total to be Recovered from Customers	**$166,460**	**$86,870**	**$142,521**	**$125,909**	**$39,880**	**$561,640**

1. Postage/Mail Service/Stationery Costs and WCA savings = historical average X 4/12ths

2. Refer to Table 4.2B for detailed calculation

Table 4.2 B – Working Capital Allowance Savings – Transition to Monthly Billing

Description	2014 CoS (EB-2013-0115)	Adjusted for Monthly Billing	Working Capital Allowance Savings per Year
	a	b	c = a-b
Total Expenses for Working Capital	$208,278,793	$208,278,793	$0
Working Capital Allowance % [1]	13.00%	11.48%	1.52%
Total Working Capital Allowance	**$27,076,243**	**$23,910,405**	**$3,165,838**
Weighted Average Cost of Capital (WACC) % [2]	5.48%	5.48%	0.00%
WACC $	**$1,483,778**	**$1,310,290**	**$173,488**

1. 1.52% reduction = 4.2% adjustment to WCA % * 36.5% of BHI customers who switched from bi-monthly to monthly billing (per Table 1 in 9-SEC-35)
2. reflects ~1% reduction in deemed WACC to reflect BHI's actual WACC over the 2017-2019 period

c) *Group 2 DVAs – OEB Cost Assessment:* For the purposes of settlement the Parties agree that the forecasted amount proposed for disposition of $452,018, as identified in Table 4.2C below, is appropriate. The Parties agree to forecast and dispose of the balance in the account up to April 30, 2021 so that the account can be discontinued effective May 1, 2021.

Table 4.2C – OEB Cost Assessment

Description	Amount in Rates	Amount Billed	Principal Amount Recorded in DVA
2016	$154,500	$226,832	$72,332
2017	$206,000	$305,720	$99,720
2018	$206,000	$283,368	$77,368
2019	$206,000	$286,124	$80,124
Total to Dec 31, 2019	**$772,500**	**$1,102,044**	**$329,543**
2020 Bridge Year	$206,000	$284,735	$78,735
2021 Test Year	$68,667	$94,667	$26,000
Total Principal Requested for Dispostion	**$1,047,167**	**$1,481,446**	**$434,278**
Total Carrying Charges			**$17,740**
Total Amount Requested for Dispostion			**$452,018**

d) *Group 2 DVAs – Account 1592 PILS & Tax Variance – CCA Changes:* In June 2019, Bill C-97, also known as the Budget Implementation Act, 2019, No.1, was passed by the Parliament of Canada and received Royal Assent in June 2019. The legislation provides for accelerated Capital Cost Allowance ("**CCA**") deductions for eligible property available for use and acquired after November 20, 2018. The OEB released guidance on July 25, 2019 which instructed utilities to record 100% of the impact of the rule change in a Sub-Account of 1592 - PILs and Tax Variances - CCA Changes, ("Account 1592 sub-account CCA") effective November 21, 2018 until the effective date of the utility's next cost-based rate order.

As directed, BHI recorded the full revenue requirement impact of the legislative change for 2018-2019 in Account 1592 sub-account CCA. BHI calculated the revenue requirement impact of this change using the additions approved in its last rebasing application.[17] It also proposed to share the balance in this account on a 50/50 basis between BHI and ratepayers consistent with the OEB's long-standing practice with respect to the impact of changes in taxes due to regulatory or legislated tax changes during an incentive rate-setting period has been to share the impacts between distributor shareholders and ratepayers on a 50/50 basis.[18]

For the purposes of settlement, the Parties agree to calculate the balance in Account 1592 sub-account CCA based on actual capital expenditures from 2018-2019 and forecasted capital expenditures in 2020. The Parties also agree to refund 100% of the balance in this account to ratepayers as identified in Table 4.2D below.

Table 4.2D –PILs & Tax Variance – CCA Changes

Description	2018	2019	2020	Total
CCA Old Rules	$7,468,431	$7,692,514	$7,956,682	$23,117,627
Accelerated CCA	$7,862,774	$8,656,878	$8,631,638	$25,151,290
Difference in CCA	($394,343)	($964,364)	($674,956)	($2,033,662)
Tax Impact @ 26.5%	($104,501)	($255,556)	($178,863)	($538,921)
Grossed up PILs	**($142,178)**	**($347,696)**	**($243,352)**	**($733,225)**
Add Carrying Charges				($15,835)
Total Payable to Ratepayers				**($749,060)**

BHI will continue use of this account to record the full revenue requirement of the phasing out period of the AIIP in 2024 and 2025, as identified in Issue 2.2 f) above.

e) *Group 2 DVAs – LRAMVA:* BHI has claimed lost revenue on CDM programs as identified in its LRAMVA Workform to December 31, 2020. The Parties agree that the LRAMVA balance as filed in the LRAMVA Workform as part of this Settlement Proposal and in Table 4.2F below is appropriate. The parties agree that BHI can continue use of this account to record future lost revenues. BHI expects to incur lost revenue in 2021-2025, which is not captured in the CDM adjustment in its proposed 2021 Load forecast.

[17] Eb-2013-0115
[18] EB-2007-0673: *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Section 3 - Tax Changes in Relation to the Z-factor*, p.35

f) *Group 2 DVAs - IFRS-CGAAP Transitional PP&E Amounts:* The Parties agree that the losses on disposals for the stub period (January 1 – April 30, 2021) will not be recorded in this DVA; and that the principal balance in this DVA of $739,241 representing losses on disposals from January 1, 2014 to December 31, 2020 is appropriate. The Parties agree that the Rate of Return will be updated to reflect the Weighted Average Cost of Capital of 5.13% as proposed in this Settlement Proposal. These changes are identified in Settlement_Attachment_IFRS_OEB_Chapter2Appendices_BHI, and in Table 4.2D below.

Table 4.2E - Account 1575 - IFRS-CGAAP Transitional PP&E Amounts

	2014	2015	2016	2017	2018	2019	2020 Bridge Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFR**	**MIFRS**	**MIFRS**	**MIFRS**
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**
						$	$
PP&E Values under CGAAP							
Opening net PP&E - Note 1	105,488,001	107,736,451	112,493,613	114,798,331	118,172,262	123,580,777	121,291,012
Net Additions - Note 4	6,778,535	10,326,803	7,818,868	8,846,798	12,182,255	-1,637,837	10,501,191
Net Depreciation (amounts should be negative) - Note 4	-4,530,086	-5,569,640	-5,514,150	-5,472,867	-6,773,740	-651,928	-6,850,359
Closing net PP&E (1)	107,736,451	112,493,613	114,798,331	118,172,262	123,580,777	121,291,012	124,941,844
PP&E Values under MIFRS (Starts from 2014, the transition year)							
Opening net PP&E - Note 1	105,488,001	107,736,451	112,355,315	114,627,012	117,979,543	123,101,720	120,741,692
Net Additions - Note 4	6,778,535	10,018,556	7,756,916	8,766,731	11,532,983	-1,829,979	9,945,367
Net Depreciation (amounts should be negative) - Note 4	-4,530,086	-5,399,692	-5,485,218	-5,414,200	-6,410,807	-530,048	-6,484,756
Closing net PP&E (2)	107,736,451	112,355,315	114,627,012	117,979,543	123,101,720	120,741,692	124,202,303
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP	0	138,299	171,319	192,720	479,058	549,320	739,541

Effect on Deferral and Variance Account Rate Riders			
Closing balance in Account 1575	739,541	**WACC**	5.13%
Return on Rate Base Associated with Account 1575 balance at WACC - Note 2	75,834	**# of years of rate rider disposition period**	2
Amount included in Deferral and Variance Account Rate Rider Calculation	815,375		

g) *Group 2 DVAs – All Other:* The Parties agree that the balances in the following DVAs as originally filed October 30, 2020 and as identified in Table 4.2E below, are appropriate:

- Deferred IFRS Transition Costs
- Pole Attachment Charges Revenues Variance
- Collection Charges Lost Revenue
- ICM - Tremaine TS CCRA (Project 1) - Actual Rate Rider
- ICM - Tremaine TS Breakers (Project 2) - Actual Rate Rider
- RCVA - Retail Services
- RCVA - Services Transaction Requests
- Extraordinary Event Costs (Z Factor) - 2018 Wind Storm

h) *Disposition Period*: The parties agree to a disposition period of two years for all Group 1 and Group 2 DVAs.

i) *Continuation/Discontinuation of DVAs:* The Parties agree to discontinue all Group 2 DVAs as at April 30, 2021, as identified in Table 4.2F below, with the exception of the following Group 2 DVAs which will continue beyond April 30, 2021:

- Other Regulatory Assets - Collection Charges Lost Revenue
- PILs & Tax Variance - CCA Changes
- Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")

j) *Account 1509 – Impacts Arising from the COVID-19 Emergency*: On March 25, 2020 and April 29, 2020, the OEB issued accounting orders for the establishment of deferral accounts to record impacts arising from the COVID-19 Emergency. The OEB established Account 1509 - Impacts Arising from the COVID-19 Emergency, which initially included three sub-accounts. These sub-accounts are for costs associated with the following:
- billing and system changes related to the Government of Ontario’s emergency order regarding time-of-use pricing;
- lost revenue; and
- other incremental costs.

During the month of August 2020, through the issuance of two separate accounting orders, the OEB confirmed the establishment of two additional sub-accounts under Account 1509 as follows:

- Forgone Revenues from Postponing Rate Implementation Sub-Account, the purpose of which is to record forgone revenues due to the postponement of rate implementation as a result of the COVID-19 Emergency; and
- Bad Debt Sub-Account, which is intended for recording amounts related to bad debt resulting from the COVID-19 Emergency.

The Parties agree that as of May 1, 2021, BHI will not record any amounts in Account 1509 - Impacts Arising from the COVID-19 Emergency – Lost Revenues. Parties agree that BHI will, however, be permitted to continue recording amounts in the remaining 1509 Accounts Sub-Accounts for as long as the OEB permits the sub-accounts to remain in place. For this purpose, the utility will follow the methodology and clearance guidelines which ultimately emerge from the OEB consultation that is underway as of the filing of this Settlement Proposal (EB-2020-0133).[19] All Parties may take any position they deem appropriate at the time BHI seeks clearance of any balance.

k) *New Deferral and Variance Accounts* – As identified under Issue 2.1, the Parties agree to establish two separate asymmetrical capital variance accounts for the Dundas Street Road Widening Project and the Waterdown Rd Road Widening Project. Parties propose to record the revenue requirement due to variances between the 2021 budgeted and actual net capital additions in the 2021 Test Year and the subsequent IRM period for each project.

For each project, if the budgeted net capital additions in the 2021 Test Year exceed actual net capital additions, BHI will make an entry in the applicable variance account in the 2021 Test Year, for the revenue requirement impact associated with the difference, representing a refund to ratepayers. For the purposes of settlement only, BHI will also record this revenue requirement difference in each subsequent rate year until rebasing, as if that variance was never included in 2021 base rates. Specifically, for each rate year from 2022 until its next rebasing application, BHI will make further entries into the applicable variance account, equal to the revenue requirement impact in the 2021 Test Year, escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor). If the actual net capital additions in the 2021 Test Year exceed budgeted net capital additions, no entry will be made to the variance account.

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 Plan shall be used, which is consistent with the treatment of the CCA on the capital additions in the 2021 Test Year. All components of cost of capital

[19] For reference purposes, BHI has budgeted $200,000 in bad debt expense for the 2021 Test Year 2021, as identified in OEB Appendix 2-JC in the Customer Service program.

will use the weighted average cost of debt and return on equity %, and capital structure, as approved in this Application.

The balance of the account will be disposed at BHI's next rebasing application. The accounting orders are attached as Appendix B to this Settlement Proposal.

Table 4.2F – Deferral and Variance Account Balances

Variance Account	Incorporate Principal Activity to:	USoA	Application	Interrogatories	Variance	Settlement	Variance
			a	b	c = b-a	d	e = d-b
Group 1							
Smart Metering Entity	12/31/2019	1551	($10,024)	($10,024)	$0	($10,024)	$0
RSVA - Wholesale Market Service Charge	12/31/2019	1580	($279,667)	($279,667)	$0	($279,667)	$0
RSVA - Wholesale Market Service Charge - CBR B	12/31/2019	1580	($116,212)	($116,212)	$0	($116,212)	$0
RSVA - Retail Transmission Network Charge	12/31/2019	1584	$69,498	$69,498	$0	$69,498	$0
RSVA - Retail Transmission Connection Charge	12/31/2019	1586	$251,624	$251,624	$0	$251,624	$0
RSVA - Power	12/31/2019	1588	$572,229	$572,229	$0	$572,229	$0
RSVA - Global Adjustment	12/31/2019	1589	$1,945,901	$1,945,901	$0	$1,945,901	$0
Disposition and Recovery of Regulatory Balances 1595 (2016)	12/31/2019	1595	$0	$0	$0	$0	$0
Disposition and Recovery of Regulatory Balances 1595 (2017)	12/31/2019	1595	($0)	($0)	$0	($0)	$0
Total Group 1 Balances			**$2,433,347**	**$2,433,347**	**$0**	**$2,433,347**	**$0**
Group 2							
Other Regulatory Assets - Deferred IFRS Transition Costs	04/30/2021	1508	$328,603	$328,603	$0	$328,603	$0
Other Regulatory Assets - Pole Attachment Charge Revenues Variance	04/30/2021	1508	($727,884)	($727,884)	$0	($727,884)	$0
Other Regulatory Assets - Monthly Billing Incremental Costs	04/30/2021	1508	$851,260	$851,260	$0	$561,640	($289,620)
Other Regulatory Assets - OEB Cost Assessment Variance	04/30/2021	1508	$452,018	$452,018	$0	$452,018	$0
Other Regulatory Assets - Collection Charges Lost Revenue	12/31/2019	1508	$280,898	$280,898	$0	$280,898	$0
ICM - Tremaine TS CCRA (Project 1) - Actual Rate Rider	04/30/2021	1508	($264,861)	($264,861)	$0	($264,861)	$0
ICM - Tremaine TS CCRA (Project 1) - Revenue Requirement [1]	04/30/2021	1508	$87,006	$87,006	$0	$87,006	$0
ICM - Tremaine TS CCRA (Project 1) - Net	04/30/2021	1508	($177,855)	($177,855)	$0	($177,855)	$0
ICM - Tremaine TS Breakers (Project 2) - Actual Rate Rider	04/30/2021	1508	($197,344)	($197,344)	$0	($197,344)	$0
ICM - Tremaine TS Breakers (Project 2) - Revenue Requirement [1]	04/30/2021	1508	$215,278	$215,278	$0	$215,278	$0
ICM - Tremaine TS Breakers (Project 2) - Net	04/30/2021	1508	$17,934	$17,934	$0	$17,934	$0
RCVA - Retail Services	04/30/2021	1518	($3,617)	($3,617)	$0	($3,617)	$0
RCVA - Services Transaction Requests	04/30/2021	1548	$2,598	$2,598	$0	$2,598	$0
Extraordinary Event Costs (Z Factor) - 2018 Wind Storm	04/30/2021	1572	$8,391	$8,391	$0	$8,391	$0
PILs & Tax Variance - CCA Changes - 100% Ratepayer	12/31/2020	1592	($192,553)	($192,553)	$0	($749,060)	($556,507)
Total Group 2 Balances before LRAM/1575			**$839,793**	**$839,793**	**$0**	**($6,334)**	**($846,127)**
Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	12/31/2020	1568	$1,039,196	$1,039,196	$0	$1,063,292	$24,096
Total Group 2 Balances before 1575			**$1,878,989**	**$1,878,989**	**$0**	**$1,056,958**	**($822,031)**
IFRS-CGAAP Transitional PP&E Amounts	12/31/2020	1575	$829,462	$829,462	$0	$739,541	($89,921)
Total Group 2 Balances			**$2,708,451**	**$2,708,451**	**$0**	**$1,796,498**	**($911,953)**
Total DVA Balances			**$5,141,798**	**$5,141,798**	**$0**	**$4,229,846**	**($911,953)**

Change in time period included for disposition from Original Application to Settlement Proposal

1. ICM revenue requirement is not recorded in RRRs; however BHI is proposing to dispose of the difference between the rate rider collected and the calculated revenue requirement

Table 4.2G – Continuation/Discontinuation of Group 2 DVAs

Group 2 Account Description	USoA	Continue/ Discontinue	Amounts included in Proposed Disposition	Rationale
Other Regulatory Assets - Deferred IFRS Transition Costs	1508	Discontinue	to Dec 31, 2019 plus interest to Apr 30, 2021	IFRS conversion completed January 1, 2015; no more costs incurred after conversion
Other Regulatory Assets - Pole Attachment Charge Revenues Variance	1508	Discontinue	to Apr 30, 2021 plus interest to Apr 30, 2021	Account to be in effect until April 30, 2021; new pole attachment charge is incorporated into 2021 Test Year revenue requirement; there will be activity past December 31, 2019 until April 30, 2021; BHI has forecast activity to April 30, 2021
Other Regulatory Assets - Monthly Billing Incremental Costs	1508	Discontinue	to Apr 30, 2021 plus interest to Apr 30, 2021	Account to be in effect until April 30, 2021; there will be activity past December 31, 2019 until April 30, 2021; BHI has forecast activity to April 30, 2021
Other Regulatory Assets - OEB Cost Assessment Variance	1508	Discontinue	to Apr 30, 2021 plus interest to Apr 30, 2021	Discontinue effective April 30, 2021; there will be activity past December 31, 2019 until April 30, 2021; BHI has forecast activity to April 30, 2021
Other Regulatory Assets - Collection Charges Lost Revenue	1508	Continue	to Dec 31, 2019 plus interest to Apr 30, 2021	Account to be in effect until BHI's next rebasing Application; there will be no lost revenue after rates are reset without the inclusion of the Collection of Account revenue; there will be activity past December 31, 2019 until April 30, 2021; BHI has not included principal activity past Dec 31, 2019.
ICM - Tremaine TS CCRA (Project 1) - Actual Rate Rider	1508	Discontinue	to Apr 30, 2020 plus interest to Apr 30, 2021	Rate rider in effect until April 30, 2020
ICM - Tremaine TS Breakers (Project 2) - Actual Rate Rider	1508	Discontinue	to Apr 30, 2021 plus interest to Apr 30, 2021	Rate rider in effect until April 30, 2021
RCVA - Retail Services	1518	Discontinue	to Apr 30, 2021 plus interest to Apr 30, 2021	Account to be discontinued April 30, 2021; final disposition at rebasing; BHI forecast activity to April 30, 2021
RCVA - Services Transaction Requests	1548	Discontinue	to Apr 30,2021 plus interest to Apr 30, 2021	Account to be discontinued April 30, 2021; final disposition at rebasing; BHI forecast activity to April 30, 2021
Extraordinary Event Costs (Z Factor) - 2018 Wind Storm	1572	Discontinue	to Apr 30, 2020 plus interest to Apr 30, 2021	Rate rider in effect until April 30, 2020
PILs & Tax Variance - CCA Changes	1592	Continue	to Dec 31, 2020 plus interest to Apr 30, 2021	Account to be in effect until BHI's next rebasing Application to record the revenue requirement impact of the phase out of AIIP in 2024 and 2025
Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	1568	Continue	to Dec 31, 2020 plus interest to Apr 30, 2021	BHI has claimed lost revenue on CDM programs to December 31, 2020; BHI expects lost revenue in 2021 due to the extension of CFF submission deadlines to June 30, 2021; and the MENDM announcement of a new CDM framework effect January 4, 2021
IFRS-CGAAP Transitional PP&E Amounts	1575	Discontinue	to December 30, 2020 plus rate of return	IFRS conversion completed January 1, 2015; Parties agree that BHI will not record losses on disposal in the stub period (January 1 to April 30, 2021)

The proposal for treatment and disposition of all deferral and variance accounts is identified in Tables 4.2D/E above and Attachment: Settlement_Attachment_DVA_Continuity_Schedule_BHI of this Settlement Proposal.

The updated DVA rate riders are provided in Tables 4.2H to 4.2L below.

Table 4.2H – 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	520,340,552	$158,078	$0.0002
GS<50 kW	kWh	168,693,830	$53,406	$0.0002
GS>50 kW	kW	2,334,671	$273,175	$0.0585
Unmetered Scattered Load	kWh	3,103,371	$998	$0.0002
Street Lighting	kW	15,528	$1,791	$0.0577
Total			**$487,447**	

Table 4.2I – Account 1589 Rate Riders by Rate Class

Rate Class	Billing Determinant	non-RPP kWhs	Allocated GA Balance	Rate Rider for GA
Residential	kWh	6,764,427	$23,071	$0.0017
GS<50 kW	kWh	23,111,055	$78,823	$0.0017
GS>50 kW	kWh	518,873,325	$1,769,686	$0.0017
Unmetered Scattered Load	kWh	-	$0	$0.0000
Street Lighting	kWh	5,525,087	$18,844	$0.0017
Total			**$1,890,425**	

Table 4.2J – Group 2 DVA Rate Riders by Rate Class (excluding 1575 and 1568)

Rate Class	Billing Determinant	# customers/ kWh/kW	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	# of Customers	62,056	($208,666)	($0.1401)
GS<50 kW	kWh	168,693,830	($18,477)	($0.0001)
GS>50 kW	kW	2,334,671	$223,019	$0.0478
Unmetered Scattered Load	kWh	3,103,371	($967)	($0.0002)
Street Lighting	kW	15,528	($1,242)	($0.0400)
Total			**($6,334)**	

Table 4.2K – Account 1575 Rate Riders by Rate Class

Rate Class	Billing Determinant	# customers/ kWh/kW	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	# of Customers	62,056	$248,674	$0.1670
GS<50 kW	kWh	168,693,830	$80,620	$0.0002
GS>50 kW	kW	2,334,671	$406,101	$0.0870
Unmetered Scattered Load	kWh	3,103,371	$1,483	$0.0002
Street Lighting	kW	15,528	$2,662	$0.0857
Total			**$739,541**	

Table 4.2L – Account 1568 Rate Riders by Rate Class

Rate Class	Billing Determinant	kWh/kW	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
Residential	kWh	520,340,552	$42,140	$0.0000
GS<50 kW	kWh	168,693,830	$337,245	$0.0010
GS>50 kW	kW	2,334,671	$553,633	$0.1186
Unmetered Scattered Load	kWh	3,103,371	($1,224)	($0.0002)
Street Lighting	kW	15,528	$131,499	$4.2342
Total			**$1,063,292**	

Evidence:

Application:
Exhibit 1 Section 1.6 H
Exhibit 9

IRs:
1-Staff-6, 2-Staff-32, 2-Staff-33, 4-Staff-56, 4-Staff-57, 4-Staff-58, 4-Staff-59, 9-Staff-72, 9-Staff-73, 9-Staff-74, 9-Staff-75, 9-Staff-76, 9-Staff-77, 9-Staff-78, 9-Staff-79, 9-Staff-80, 9-Staff-81, 9-Staff-82, CCC-5, 1-SEC-6, 9-SEC-35, 9-SEC-36, 2.0-VECC-3, 4.0-VECC-43

Appendices to this Settlement Proposal:
None

Settlement Models:
Settlement_Attachment_2021 LRAMVA Workform_BHI
Settlement_Attachment_DVA_Continuity_Schedule_BHI
Settlement_Attachment_IFRS_OEB_Chapter2Appendices_BHI

Clarifying Question Responses:
CQ-4-Staff-95, CQ-9-Staff-96, CQ-9-Staff-97, CQ-9-Staff-98, CQ-9-Staff-99, CQ-9-SEC-4, CQ-3-VECC-79

Supporting Parties: All
Parties Taking No Position: ED

5.0 Other

5.1 Is the proposed effective date (i.e. May 1, 2021) for 2021 rates appropriate?

Complete Settlement:
The Parties agree that the proposed effective date of May 1, 2021 is appropriate and that BHI be permitted to establish an account to recover any differences between its current rates and the actual rates effective May 1, 2021 if a Decision and Rate Order cannot be issued by the OEB in time to implement rates effective May 1, 2021.

Evidence:

Application:
Exhibit 1 Section 1.4.10
Exhibit 1 Section 1.4.16

IRs:
CCC-2

Appendices to this Settlement Proposal:
None

Settlement Models:
None

Clarifying Question Responses:
None

Supporting Parties: All
Parties Taking No Position: ED

5.2 Has Burlington Hydro responded appropriately to the requirement to address the savings and/or other beneficial impacts resulting from its operational effectiveness initiatives as outlined in the approved EB-2013-0115 settlement proposal?

Complete Settlement:
The Parties agree that BHI has responded appropriately to the requirement to address the savings and/or other beneficial impacts resulting from its operational effectiveness initiatives as outlined in the approved EB-2013-0115 settlement proposal.

Evidence:

Application:
Exhibit 1 Section 1.2.8
Exhibit 4 Section 4.1.1.12

IRs:
1-Staff-4, CCC-7, 1-SEC-7

Appendices to this Settlement Proposal:
None

Settlement Models:
None

Clarifying Question Responses:
CQ-1-SEC-1

Supporting Parties: All
Parties Taking No Position: ED

Appendix A
Proposed Tariff of Rates and Charges

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

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	$	28.23
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2023	$	(0.14)
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$	0.17
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	0.0000
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0066

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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

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	$	25.32
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0168
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2023	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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

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	$	68.03
Distribution Volumetric Rate	$/kW	3.3327
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2023	$/kW	0.0585
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kW	0.0870
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2023	$/kW	0.0478
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kW	0.1186
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.3799
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.5910

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

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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

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	$	9.36
Distribution Volumetric Rate	$/kWh	0.0163
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0000
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2023	$/kWh	(0.0002)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kWh	(0.0002)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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

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)	$	0.56
Distribution Volumetric Rate	$/kW	4.0390
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2023	$/kW	0.0577
Rate Rider for Disposition of Account 1575 - effective until April 30, 2023	$/kW	0.0857
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2023	$/kWh	0.0017
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2023	$/kW	(0.0400)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2023	$/kW	4.2342
Retail Transmission Rate - Network Service Rate	$/kW	2.4700
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.8439

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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

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	$	4.55

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 (with the exception of wireless attachments)	$	44.50

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	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
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)	$	4.17
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)	$	2.08

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

Appendix B
Accounting Orders

Accounting Order #1
Burlington Hydro Inc.
EB-2020-0007

Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account

Effective May 1, 2021, BHI shall establish a new variance account: Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account ("CVA1"). The purpose of this sub-account is to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Dundas Street Road Widening Project and the resulting impact during the IRM period. If the revenue requirement impact is lower than forecast in the 2021 Test Year, (budgeted net capital additions in the 2021 Test Year exceed actual net capital additions), BHI will make a credit entry in the applicable variance account representing a refund to ratepayers. This is an asymmetrical account and as such, if the revenue requirement impact is higher than forecast in the 2021 Test Year, (actual capital additions in the 2021 Test Year exceed budgeted capital additions), no entry will be made to the variance account. 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 Plan shall be used, which is consistent with the treatment of the CCA on the capital additions in the 2021 Test Year. All components of cost of capital will use the weighted average cost of debt and return on equity %, and capital structure, as approved in BHI's Cost of Service Application EB-2020-0007.

If the budgeted net capital additions in the 2021 Test Year exceed actual net capital additions, for each rate year from 2022 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2021 Test Year associated with the difference between budgeted and actual net capital additions, escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year.

The variance account will be disposed at BHI's next rebasing application, if applicable, as per the OEB's guidelines related to Group 2 Accounts. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries for underspending on the Dundas Street Road Widening Project in the 2021 Test Year and IRM years. (i.e., actual net capital additions are less than budgeted net capital additions).

	Debit	Credit
DR. Account 4080 - Distribution Services Revenue	x,xxx.xx	
CR. Account 1508 - Sub-account CVA1 – Depreciation		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – Deemed Interest Expense		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – Return on Equity		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – PILs		x,xxx.xx
DR. Account 6035 - Interest Expense	x,xxx.xx	
CR. Account 1508 - Sub-account CVA1 – Carrying Charges		x,xxx.xx

Accounting Order #2
Burlington Hydro Inc.
EB-2020-0007

Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account

Effective May 1, 2021, BHI shall establish a new variance account: Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account ("CVA2"). The purpose of this sub-account is to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Waterdown Rd Road Widening Project and the resulting impact during the IRM period. If the revenue requirement impact is lower than forecast in the 2021 Test Year, (budgeted net capital additions in the 2021 Test Year exceed actual net capital additions), BHI will make a credit entry in the applicable variance account representing a refund to ratepayers. This is an asymmetrical account and as such, if the revenue requirement impact is higher than forecast in the 2021 Test Year, (actual capital additions in the 2021 Test Year exceed budgeted capital additions), no entry will be made to the variance account. 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 Plan shall be used, which is consistent with the treatment of the CCA on the capital additions in the 2021 Test Year. All components of cost of capital will use the weighted average cost of debt and return on equity %, and capital structure, as approved in BHI's Cost of Service Application EB-2020-0007.

If the budgeted net capital additions in the 2021 Test Year exceed actual net capital additions, for each rate year from 2022 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2021 Test Year associated with the difference between budgeted and actual net capital additions, escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year.

The variance account will be disposed at BHI's next rebasing application, if applicable, as per the OEB's guidelines related to Group 2 Accounts. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries for underspending on the Waterdown Rd Road Widening Project in the 2021 Test Year and IRM years. (i.e., actual net capital additions are less than budgeted net capital additions).

	Debit	Credit
DR. Account 4080 - Distribution Services Revenue	x,xxx.xx	
CR. Account 1508 - Sub-account CVA2 – Depreciation		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – Deemed Interest Expense		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – Return on Equity		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – PILs		x,xxx.xx
DR. Account 6035 - Interest Expense	x,xxx.xx	
CR. Account 1508 - Sub-account CVA2 – Carrying Charges		x,xxx.xx

Appendix C
Revenue Requirement Workform

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Version 1.00

Utility Name	Burlington Hydro Inc.
Service Territory	
Assigned EB Number	EB-2020-0007
Name and Title	Sally Blackwell, VP Regulatory Compliance and As
Phone Number	905-336-4373
Email Address	sblackwell@burlingtonhydro.com
Test Year	2021
Bridge Year	2020
Last Rebasing Year	2014

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Settlement Agreement	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$309,790,789		($254,684)	$ 309,536,105			$309,536,105	
	Accumulated Depreciation (average)	($177,210,289)	(5)	($49,155)	($177,259,444)			($177,259,444)	
	Allowance for Working Capital:								
	Controllable Expenses	$21,839,565		($940,000)	$ 20,899,565			$20,899,565	
	Cost of Power	$191,444,505		($12,228,308)	$ 179,216,197			$179,216,197	
	Working Capital Rate (%)	7.50%	(9)	$0	7.50%	(9)	$0	7.50%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$31,626,573		$218,395	$31,844,968				
	Distribution Revenue at Proposed Rates	$35,529,884		($1,612,859)	$33,917,025				
	Other Revenue:								
	Specific Service Charges	$226,581		$0	$226,581				
	Late Payment Charges	$294,000		$0	$294,000				
	Other Distribution Revenue								
	Other Income and Deductions	$1,170,506		$1,388,080	$2,558,586				
	Total Revenue Offsets	$1,691,087	(7)	$1,388,080	$3,079,167				
	Operating Expenses:								
	OM+A Expenses	$21,497,775		($940,000)	$ 20,557,775			$20,557,775	
	Depreciation/Amortization	$6,883,779		$1,262,774	$ 8,146,553			$8,146,553	
	Property taxes	$341,790		$ -	$ 341,790			$341,790	
	Other expenses								
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($3,346,741)	(3)	($113,031)	($3,459,772)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$336,023		($43,072)	$292,952				
	Income taxes (grossed up)	$457,175			$398,574				
	Federal tax (%)	15.00%		$0	15.00%		$0	15.00%	
	Provincial tax (%)	11.50%		$0	11.50%		$0	11.50%	
	Income Tax Credits	($118,917)		$26,647	($92,270)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%		$0	56.0%		$0	56.0%	
	Short-term debt Capitalization Ratio (%)	4.0%	(8)	$0	4.0%	(8)	$0	4.0%	(8)
	Common Equity Capitalization Ratio (%)	40.0%		$0	40.0%		$0	40.0%	
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%			100.0%	
	Cost of Capital								
	Long-term debt Cost Rate (%)	3.38%		($0)	3.07%		$0	3.07%	
	Short-term debt Cost Rate (%)	2.75%		($0)	1.75%		$0	1.75%	
	Common Equity Cost Rate (%)	8.52%		($0)	8.34%		$0	8.34%	
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use column M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M12. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is **7.5%** (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, a WCA factor based on lead-lag study, with supporting rationale could be provided.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(2)	$309,790,789	($254,684)	$309,536,105	$ -	$309,536,105
2	Accumulated Depreciation (average)	(2)	($177,210,289)	($49,155)	($177,259,444)	$ -	($177,259,444)
3	Net Fixed Assets (average)	(2)	$132,580,500	($303,839)	$132,276,661	$ -	$132,276,661
4	Allowance for Working Capital	(1)	$15,996,305	($987,623)	$15,008,682	$ -	$15,008,682
5	**Total Rate Base**		$148,576,805	($1,291,462)	$147,285,343	$ -	$147,285,343

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$21,839,565	($940,000)	$20,899,565	$ -	$20,899,565
7	Cost of Power		$191,444,505	($12,228,308)	$179,216,197	$ -	$179,216,197
8	Working Capital Base		$213,284,070	($13,168,308)	$200,115,762	$ -	$200,115,762
9	Working Capital Rate %	(1)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$15,996,305	($987,623)	$15,008,682	$ -	$15,008,682

Notes

(1) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2021 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015.

(2) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$35,529,884	($1,612,859)	$33,917,025	$ -	$33,917,025
2	Other Revenue	(1)	$1,691,087	$1,388,080	$3,079,167	$ -	$3,079,167
3	Total Operating Revenues		$37,220,971	($224,778)	$36,996,192	$ -	$36,996,192
	Operating Expenses:						
4	OM+A Expenses		$21,497,775	($940,000)	$20,557,775	$ -	$20,557,775
5	Depreciation/Amortization		$6,883,779	$1,262,774	$8,146,553	$ -	$8,146,553
6	Property taxes		$341,790	$ -	$341,790	$ -	$341,790
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$28,723,345	$322,774	$29,046,118	$ -	$29,046,118
10	Deemed Interest Expense		$2,976,954	($338,893)	$2,638,061	$ -	$2,638,061
11	Total Expenses (lines 9 to 10)		$31,700,298	($16,119)	$31,684,179	$ -	$31,684,179
12	**Utility income before income taxes**		$5,520,672	($208,659)	$5,312,013	$ -	$5,312,013
13	Income taxes (grossed-up)		$457,175	($58,601)	$398,574	$ -	$398,574
14	**Utility net income**		$5,063,498	($150,058)	$4,913,439	$ -	$4,913,439

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
(1)	Specific Service Charges	$226,581	$ -	$226,581		$226,581
	Late Payment Charges	$294,000	$ -	$294,000		$294,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$1,170,506	$1,388,080	$2,558,586		$2,558,586
	Total Revenue Offsets	$1,691,087	$1,388,080	$3,079,167	$ -	$3,079,167

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Revenue Requirement Workform (RRWF) for 2021 Filers

Taxes/PILs

Line No.	Particulars	Application	Settlement Agreement	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$5,063,498	$4,913,439	$4,913,439
2	Adjustments required to arrive at taxable utility income	($3,346,741)	($3,459,772)	($3,459,772)
3	Taxable income	$1,716,756	$1,453,667	$1,453,667
	Calculation of Utility income Taxes			
4	Income taxes	$336,023	$292,952	$292,952
6	Total taxes	$336,023	$292,952	$292,952
7	Gross-up of Income Taxes	$121,151	$105,622	$105,622
8	Grossed-up Income Taxes	$457,175	$398,574	$398,574
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$457,175	$398,574	$398,574
10	Other tax Credits	($118,917)	($92,270)	($92,270)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$83,203,011	3.38%	$2,813,519
2	Short-term Debt	4.00%	$5,943,072	2.75%	$163,434
3	**Total Debt**	60.00%	$89,146,083	3.34%	$2,976,954
	Equity				
4	Common Equity	40.00%	$59,430,722	8.52%	$5,063,498
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$59,430,722	8.52%	$5,063,498
7	**Total**	100.00%	$148,576,805	5.41%	$8,040,451
	Settlement Agreement				
	Debt				
1	Long-term Debt	56.00%	$82,479,792	3.07%	$2,534,961
2	Short-term Debt	4.00%	$5,891,414	1.75%	$103,100
3	**Total Debt**	60.00%	$88,371,206	2.99%	$2,638,061
	Equity				
4	Common Equity	40.00%	$58,914,137	8.34%	$4,913,439
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$58,914,137	8.34%	$4,913,439
7	**Total**	100.00%	$147,285,343	5.13%	$7,551,500
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$82,479,792	3.07%	$2,534,961
9	Short-term Debt	4.00%	$5,891,414	1.75%	$103,100
10	**Total Debt**	60.00%	$88,371,206	2.99%	$2,638,061
	Equity				
11	Common Equity	40.00%	$58,914,137	8.34%	$4,913,439
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$58,914,137	8.34%	$4,913,439
14	**Total**	100.00%	$147,285,343	5.13%	$7,551,500

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,903,311		$2,072,057		$2,072,057
2	Distribution Revenue	$31,626,573	$31,626,573	$31,844,968	$31,844,968	$31,844,968	$31,844,968
3	Other Operating Revenue Offsets - net	$1,691,087	$1,691,087	$3,079,167	$3,079,167	$3,079,167	$3,079,167
4	**Total Revenue**	$33,317,660	$37,220,971	$34,924,135	$36,996,192	$34,924,135	$36,996,192
5	Operating Expenses	$28,723,345	$28,723,345	$29,046,118	$29,046,118	$29,046,118	$29,046,118
6	Deemed Interest Expense	$2,976,954	$2,976,954	$2,638,061	$2,638,061	$2,638,061	$2,638,061
8	**Total Cost and Expenses**	$31,700,298	$31,700,298	$31,684,179	$31,684,179	$31,684,179	$31,684,179
9	**Utility Income Before Income Taxes**	$1,617,361	$5,520,672	$3,239,956	$5,312,013	$3,239,956	$5,312,013
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,346,741)	($3,346,741)	($3,459,772)	($3,459,772)	($3,459,772)	($3,459,772)
11	**Taxable Income**	($1,729,380)	$2,173,931	($219,816)	$1,852,241	($219,816)	$1,852,241
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($458,286)	$576,092	($58,251)	$490,844	($58,251)	$490,844
14	**Income Tax Credits**	($118,917)	($118,917)	($92,270)	($92,270)	($92,270)	($92,270)
15	**Utility Net Income**	$2,194,564	$5,063,498	$3,390,477	$4,913,439	$3,390,477	$4,913,439
16	**Utility Rate Base**	$148,576,805	$148,576,805	$147,285,343	$147,285,343	$147,285,343	$147,285,343
17	Deemed Equity Portion of Rate Base	$59,430,722	$59,430,722	$58,914,137	$58,914,137	$58,914,137	$58,914,137
18	Income/(Equity Portion of Rate Base)	3.69%	8.52%	5.75%	8.34%	5.75%	8.34%
19	Target Return - Equity on Rate Base	8.52%	8.52%	8.34%	8.34%	8.34%	8.34%
20	Deficiency/Sufficiency in Return on Equity	-4.83%	0.00%	-2.59%	0.00%	-2.59%	0.00%
21	Indicated Rate of Return	3.48%	5.41%	4.09%	5.13%	4.09%	5.13%
22	Requested Rate of Return on Rate Base	5.41%	5.41%	5.13%	5.13%	5.13%	5.13%
23	Deficiency/Sufficiency in Rate of Return	-1.93%	0.00%	-1.03%	0.00%	-1.03%	0.00%
24	Target Return on Equity	$5,063,498	$5,063,498	$4,913,439	$4,913,439	$4,913,439	$4,913,439
25	Revenue Deficiency/(Sufficiency)	$2,868,934	$0	$1,522,962	$ -	$1,522,962	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,903,311 (1)		$2,072,057 (1)		$2,072,057 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Revenue Requirement

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$21,497,775		$20,557,775		$20,557,775	
2	Amortization/Depreciation	$6,883,779		$8,146,553		$8,146,553	
3	Property Taxes	$341,790		$341,790		$341,790	
5	Income Taxes (Grossed up)	$457,175		$398,574		$398,574	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$2,976,954		$2,638,061		$2,638,061	
	Return on Deemed Equity	$5,063,498		$4,913,439		$4,913,439	
8	**Service Revenue Requirement (before Revenues)**	$37,220,971		$36,996,192		$36,996,192	
9	Revenue Offsets	$1,691,087		$3,079,167		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$35,529,884		$33,917,025		$36,996,192	
11	Distribution revenue	$35,529,884		$33,917,025		$33,917,025	
12	Other revenue	$1,691,087		$3,079,167		$3,079,167	
13	**Total revenue**	$37,220,971		$36,996,192		$36,996,192	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	$ -	(1)	$ -	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application	Settlement Agreement	Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$37,220,971	$36,996,192	($0)	$36,996,192	($1)
Grossed-Up Revenue Deficiency/(Sufficiency)	$3,903,311	$2,072,057	($0)	$2,072,057	($1)
Base Revenue Requirement (to be recovered from Distribution Rates)	$35,529,884	$33,917,025	($0)	$36,996,192	($1)
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$3,903,311	$2,072,057	($0)	$ -	($1)

Notes

(1) Line 11 - Line 8

(2) Percentage Change Relative to Initial Application

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Settlement Agreement

	Customer Class	Initial Application			Settlement Agreement			Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential	62,056	529,231,270		62,056	520,340,552		62,056	520,340,552	
2	GS<50kW	5,564	167,003,174		5,564	168,693,830		5,564	168,693,830	
3	GS>50kW	1,003	825,433,794	2,267,945	1,004	849,749,403	2,334,671	1,004	849,749,403	2,334,671
4	Streetlighting	17,283	5,569,644	15,528	17,283	5,569,644	15,528	17,283	5,569,644	15,528
5	Unmetered Scattered Load	554	3,103,371		554	3,103,371		554	3,103,371	
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19										
20										
	Total		**1,530,341,252**	**2,283,473**		**###########**	**2,350,199**		**###########**	**2,350,199**

Notes:

(1) Input kW or kVA for those customer classes for which billing is based on demand (kW or kVA) versus energy consumption (kWh)

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Revenue Requirement Workform (RRWF) for 2021 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Settlement Agreement***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 18,706,189	60.66%	$ 23,273,829	62.91%
2	GS<50kW	$ 4,150,181	13.46%	$ 4,104,530	11.09%
3	GS>50kW	$ 7,602,005	24.65%	$ 9,355,951	25.29%
4	Streetlighting	$ 257,829	0.84%	$ 161,497	0.44%
5	Unmetered Scattered Load	$ 120,341	0.39%	$ 100,385	0.27%
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7					
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16					
17					
18					
19					
20					
	Total	$ 30,836,545	100.00%	**$ 36,996,192**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 36,996,192.05**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 19,741,165	$ 21,025,663	$ 21,025,663	$ 1,957,779
2	GS<50kW	$ 4,252,955	$ 4,529,682	$ 4,529,682	$ 334,713
3	GS>50kW	$ 7,525,842	$ 8,015,526	$ 8,070,531	$ 763,564
4	Streetlighting	$ 207,849	$ 221,373	$ 178,478	$ 15,319
5	Unmetered Scattered Load	$ 117,157	$ 124,780	$ 112,671	$ 7,792
6					
7					
8					
9					
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11					
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16					
17					
18					
19					
20					
	Total	$ 31,844,968	$ 33,917,025	$ 33,917,025	$ 3,079,167

(4) In columns 7B to 7D, LF means Load Forecast of Annual Billing Quantities (i.e., customers or connections, as applicable X 12 months, and kWh, kW or kVA as applicable. Revenue quantities should be net of the Transformer Ownership Allowance for applicable customer classes. Exclude revenues from rate adders and rate riders.

(5) Columns 7C and 7D - Column Total should equal the Base Revenue Requirement for each.

(6) Column 7C - The OEB-issued cost allocation model calculates "1+d" on worksheet O-1, cell C22. "d" is defined as Revenue Deficiency/Revenue at Current Rates.

(7) Column 7E - If using the OEB-issued cost allocation model, enter Miscellaneous Revenues as it appears on worksheet O-1, row 19,

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2014 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	105.00%	98.75%	98.75%	85 - 115
2	GS<50kW	100.00%	118.51%	118.51%	80 - 120
3	GS>50kW	89.41%	93.83%	94.42%	80 - 120
4	Streetlighting	95.96%	146.56%	120.00%	80 - 120
5	Unmetered Scattered Load	119.96%	132.06%	120.00%	80 - 120
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(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) ***Proposed Revenue-to-Cost Ratios*** [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2021	2022	2023	
1	Residential	98.75%	98.75%	98.75%	85 - 115
2	GS<50kW	118.51%	118.51%	118.51%	80 - 120
3	GS>50kW	94.42%	94.42%	94.42%	80 - 120
4	Streetlighting	120.00%	120.00%	120.00%	80 - 120
5	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
6					
7					
8					
9					
10					
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20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

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Revenue Requirement Workform (RRWF) for 2021 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Settlement Agreement*

	Customer and Load Forecast					Class Allocated Revenues (From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design)		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric
1	Residential	kWh	62,056	520,340,552	-	$ 21,025,663	$ 21,025,663	$ -
2	GS<50kW	kWh	5,564	168,693,830	-	$ 4,529,682	$ 1,691,031	$ 2,838,651
3	GS>50kW	kW	1,004	849,749,403	2,334,671	$ 8,070,531	$ 819,577	$ 7,250,954
4	Streetlighting	kW	17,283	5,569,644	15,528	$ 178,478	$ 115,759	$ 62,718
5	Unmetered Scattered Load	kWh	554	3,103,371	-	$ 112,671	$ 62,232	$ 50,439
6			-	-	-			
7			-	-	-			
8			-	-	-			
9			-	-	-			
#			-	-	-			
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	Fixed / Variable Splits [2] (Percentage to be entered as a fraction between 0 and 1)			Distribution Rates					Revenue Reconciliation		
	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Monthly Service Charge Rate	Monthly Service Charge No. of decimals	Volumetric Rate		Volumetric Rate No. of decimals	MSC Revenues	Volumetric revenues	Distribution Revenues less Transformer Ownership
1	100.00%	0.00%		$28.23	2	$0.0000	/kWh	4	$21,021,995.00	$ -	$21,021,995.00
2	37.33%	62.67%		$25.32		$0.0168	/kWh		$ 1,690,708.45	$ 2,834,056.3485	$ 4,524,764.80
3	10.16%	89.84%	$ 529,832	$68.03		$3.3327	/kW		$ 819,559.06	$ 7,780,758.5555	$ 8,070,485.22
4	64.86%	35.14%		$0.56		$4.0390	/kW		$ 116,143.58	$ 62,717.9629	$ 178,861.55
5	55.23%	44.77%		$9.36		$0.0163	/kWh		$ 62,248.89	$ 50,584.9456	$ 112,833.84
6									$ -	$ -	$ -
7									$ -	$ -	$ -
8									$ -	$ -	$ -
9									$ -	$ -	$ -
#									$ -	$ -	$ -
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Total Transformer Ownership Allowance $ 529,832

Total Distribution Revenues	$33,908,940.41
Base Revenue Requirement	$33,917,025.00
Difference	-$ 8,084.59
% Difference	-0.024%

Rates recover revenue requirement

Notes:

1 Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

2 The Fixed/Variable split, for each customer class, drives the "rate generator" portion of this sheet of the RRWF. Only the "fixed" fraction is entered, as the sum of the "fixed" and "variable" portions must sum to 100%. For a distributor that may set the Monthly Service Charge, the "fixed" ratio is calcutated as: [MSC x (average number of customers or connections) x 12 months] / (Class Allocated Revenue Requirement).

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Revenue Requirement Workform (RRWF) for 2021 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

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(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 8,040,451	5.41%	$ 148,576,805	$ 213,284,070	$ 15,996,305	$ 6,883,779	$ 457,175	$ 21,497,775	$ 37,220,971	$ 1,691,087	$ 35,529,884	$ 3,903,311
1	2-Staff-31	1. Move 2440 Deferred Revenue to Operating Revenue	$8,040,451	5.41%	$148,576,805	$213,284,070	$15,996,305	$8,082,477	$457,175	$21,497,775	$38,419,668	$2,889,784	$35,529,884	$3,903,311
		Change	$ 0	0.00%	$ 0	$ 0	$ 0	$ 1,198,697	-$ 0	$ -	$ 1,198,697	$ 1,198,697	$ 0	$ 0
2	5-Staff-63 c)	2. Update Cost of Capital Parameters (incl new LTD)	$ 7,640,142	5.14%	$ 148,576,805	$ 213,284,070	$ 15,996,305	$ 8,082,477	$ 418,605	$ 21,497,775	$ 37,980,789	$ 2,889,784	$ 35,091,005	$ 3,464,432
		Change	-$ 400,309	-0.27%	$ -	$ -	$ -	$ -	-$ 38,569	$ -	-$ 438,879	$ -	-$ 438,879	-$ 438,879
3	5-Staff-63 c)	3. Update LTD for principal change in 2021	$ 7,655,212	5.15%	$ 148,576,805	$ 213,284,070	$ 15,996,305	$ 8,082,477	$ 418,605	$ 21,497,775	$ 37,995,860	$ 2,889,784	$ 35,106,076	$ 3,479,503
		Change	$ 15,071	0.01%	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,071	$ -	$ 15,071	$ 15,071
4	2-Staff-31	4. Update Commodity Cost per Jan 1, 2021 changes	$ 7,591,481	5.15%	$ 147,339,859	$ 196,791,457	$ 14,759,359	$ 8,082,477	$ 403,728	$ 21,497,775	$ 37,917,250	$ 2,889,784	$ 35,027,466	$ 3,400,893
		Change	-$ 63,732	0.00%	-$ 1,236,946	-$ 16,492,613	-$ 1,236,946	$ -	-$ 14,878	$ -	-$ 78,610	$ -	-$ 78,610	-$ 78,610
5	8-VECC-75a); 8-Staff-69	5. Update RTSR Model for 2019 billing determin.	$7,591,481	5.15%	$147,339,859	$196,791,457	$14,759,359	$8,082,477	$403,728	$21,497,775	$37,917,250	$2,889,784	$35,027,466	$3,400,893
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Multiple IRs	6. Revised Capital Forecast	$ 7,587,851	5.15%	$ 147,269,421	$ 196,791,457	$ 14,759,359	$ 8,158,351	$ 358,050	$ 21,497,775	$ 37,943,818	$ 2,889,167	$ 35,054,651	$ 3,428,078
		Change	-$ 3,629	0.00%	-$ 70,438	$ -	$ -	$ 75,875	-$ 45,678	$ -	$ 26,568	-$ 618	$ 27,185	$ 27,185
7	7-Staff-65 and 7-VECC-72	7. Cost Allocation and Load Forecast	$ 7,587,851	5.15%	$ 147,269,421	$ 196,791,457	$ 14,759,359	$ 8,158,351	$ 358,050	$ 21,497,775	$ 37,943,818	$ 2,889,167	$ 35,054,651	$ 3,428,078
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	3-Staff-37	8. Updated Commodity for Corrected Load Forecast	$ 7,586,755	5.15%	$ 147,248,139	$ 196,507,700	$ 14,738,078	$ 8,158,351	$ 357,794	$ 21,497,775	$ 37,942,465	$ 2,889,167	$ 35,053,299	$ 3,426,726
		Change	-$ 1,097	0.00%	-$ 21,282	-$ 283,757	-$ 21,282	$ -	-$ 256	$ -	-$ 1,352	$ -	-$ 1,352	-$ 1,352
9	1-Staff-1	9. Update PILs (as per IRS filed FEB 1/2021)	$ 7,586,755	5.15%	$ 147,248,139	$ 196,507,700	$ 14,738,078	$ 8,158,351	$ 373,140	$ 21,497,775	$ 37,957,812	$ 2,889,167	$ 35,068,645	$ 3,410,371
		Change	-$ 0	0.00%	$ -	$ -	$ -	$ -	$ 15,347	$ -	$ 15,347	$ -	$ 15,347	-$ 16,355
10	CQ-VECC-79a	10. Update from Clarifying Questions (Corrections to Load Forecast)	$ 7,586,755	5.15%	$ 147,248,139	$ 196,507,700	$ 14,738,078	$ 8,158,351	$ 373,140	$ 21,497,775	$ 37,957,812	$ 2,889,167	$ 35,068,645	$ 3,401,933
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 8,438
11	Settlement Conference	11. Update Rate on $5MM drawdown to 2.227% from 2.85%	$ 7,549,592	5.13%	$ 147,248,139	$ 196,507,700	$ 14,738,078	$ 8,158,351	$ 373,140	$ 21,497,775	$ 37,920,650	$ 2,889,167	$ 35,031,483	$ 3,364,771
		Change	-$ 37,163	-0.03%	$ -	$ -	$ -	$ -	$ 0	$ -	-$ 37,163	$ -	-$ 37,163	-$ 37,163
12	Settlement Conference	12. Increase Other Revenue by $190,000	$ 7,549,592	5.13%	$ 147,248,139	$ 196,507,700	$ 14,738,078	$ 8,158,351	$ 373,140	$ 21,497,775	$ 37,920,650	$ 3,079,167	$ 34,841,483	$ 3,174,771
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 190,000	-$ 190,000	-$ 190,000
13	Settlement Conference (Staff-36a; Staff-89; Staff-	13. Update for Load Forecast (Impact to Cost of Power)	$ 7,559,349	5.13%	$ 147,438,438	$ 199,045,026	$ 14,928,377	$ 8,158,351	$ 375,429	$ 21,497,775	$ 37,932,695	$ 3,079,167	$ 34,853,529	$ 3,186,817
		Change	$ 9,757	0.00%	$ 190,299	$ 2,537,326	$ 190,299	$ -	$ 2,289	$ -	$ 12,046	$ -	$ 12,046	$ 12,046
14	8-VECC-75a, 8-Staff-69	14. Update for reduction in OM&A of $940,000 per SC	$ 7,555,735	5.13%	$ 147,367,938	$ 198,105,026	$ 14,857,877	$ 8,158,351	$ 374,581	$ 20,557,775	$ 36,988,233	$ 3,079,167	$ 33,909,066	$ 2,242,354
		Change	-$ 3,615	0.00%	-$ 70,500	-$ 940,000	-$ 70,500	$ -	-$ 848	-$ 940,000	-$ 944,463	$ -	-$ 944,463	-$ 944,463
15	2-Staff-33, S-SEC-13, CQ-2-Staff-94	15. Update for Full Year Depreciation on ICMs	$ 7,556,283	5.13%	$ 147,378,638	$ 198,105,026	$ 14,857,877	$ 8,158,351	$ 374,710	$ 20,557,775	$ 36,988,910	$ 3,079,167	$ 33,909,743	$ 2,243,031
		Change	$ 549	0.00%	$ 10,700	$ -	$ -	$ -	$ 129	$ -	$ 677	$ -	$ 677	$ 677

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2021 Filers

Tracking Form

The first row shown, labelled "Original Application", summarizes key statistics based on the data inputs into the RRWF. After the original application filing, the applicant provides key changes in capital and operating expenses, load forecasts, cost of capital, etc., as revised through the processing of the application. This could be due to revisions or responses to interrogatories. The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)

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(2) Short description of change, issue, etc.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
16	7-Staff-65 and 7-VECC-72	16. Update for reduction in 2021 Capital of $500,000 per SC	$ 7,543,768	5.13%	$ 147,134,538	$ 198,105,026	$ 14,857,877	$ 8,146,553	$ 419,366	$ 20,557,775	$ 37,009,252	$ 3,079,167	$ 33,930,085	$ 2,263,373
		Change	-$ 12,515	0.00%	-$ 244,101	$ -	$ -	-$ 11,799	$ 44,656	$ -	$ 20,342	$ -	$ 20,342	$ 20,342
17	Settlement Conference (Staff-36a; Staff-89; Staff-37h with CDM Adj	17. Update to 2021 Revenue at Existing Rates with SC Load Forecast	$ 7,543,768	5.13%	$ 147,134,538	$ 198,105,026	$ 14,857,877	$ 8,146,553	$ 419,366	$ 20,557,775	$ 37,009,252	$ 3,079,167	$ 33,930,085	$ 2,085,117
		Change	$ -	0.00%	$ -	$ -	$ -	$ 0	$ -	$ -	$ 0	$ 0	$ -	-$ 178,256
18	Settlement Conference Update for PILs	18. Update for PILs	$ 7,543,768	5.13%	$ 147,134,538	$ 198,105,026	$ 14,857,877	$ 8,146,553	$ 396,760	$ 20,557,775	$ 36,986,646	$ 3,079,167	$ 33,907,479	$ 2,062,511
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	-$ 22,606	$ -	-$ 22,606	$ -	-$ 22,606	-$ 22,606
19	Settlement Proposal Update UTRs/RTSRs	19. Update for UTRs in RTSR Model	$ 7,551,500	5.13%	$ 147,285,343	$ 200,115,762	$ 15,008,682	$ 8,146,553	$ 398,574	$ 20,557,775	$ 36,996,192	$ 3,079,167	$ 33,917,025	$ 2,072,057
		Change	$ 7,732	0.00%	$ 150,805	$ 2,010,736	$ 150,805	$ -	$ 1,814	$ -	$ 9,546	$ -	$ 9,546	$ 9,546
20														
		Change												

Appendix D
PILs Workform

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Version **1.20**

Utility Name	Burlington Hydro Inc.
Assigned EB Number	EB-2020-0007
Name and Title	Sally Blackwell, VP Regulatory Compliance and Asset Management
Phone Number	905-336-4373
Email Address	sblackwell@burlingtonhydro.com
Date	October 31, 2020
Last COS Re-based Year	**2014**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-3,459,772**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**292,952**	
Test Year - Grossed-up PILs	T0	**398,574**	
Effective Federal Tax Rate	T0	**15.0%**	
Effective Ontario Tax Rate	T0	**11.5%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	4,913,439	
Taxable Income	T1	1,453,667	
Difference	calculated	-3,459,772	as above

Income Tax/PILs Workform for 2021 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	N	LCF estimated in the bridge year are applied in the test year.
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 147,285,343**	**$ 153,033,847**	

Return on Ratebase

			Test Year		
Deemed ShortTerm Debt %	4.00%	T	$ 5,891,414	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 82,479,792	*X = S * U*	
Deemed Equity %	40.00%	V	$ 58,914,137	*Y = S * V*	
Short Term Interest Rate	1.75%	Z	$ 103,100	*AC = W * Z*	
Long Term Interest	3.07%	AA	$ 2,534,961	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.34%	AB	**$ 4,913,439**	*AE = Y * AB*	T1
Return on Rate Base			**$ 7,551,500**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	Yes	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	Yes	Yes	Yes
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Tax Rates **Federal & Provincial** **As of MMM XX, 2019**	**Effective January 1, 2015**	**Effective January 1, 2016**	**Effective January 1, 2017**	**Effective January 1, 2018**	**Effective January 1, 2019**	**Effective January 1, 2020**
Federal income tax						
General Corporate Rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal Tax Abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted Federal Rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate Reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined Federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business						
Federal Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000
Federal Small Business Rate	11.00%	10.50%	10.50%	10.00%	9.00%	9.00%
Ontario Small Business Rate	4.50%	4.50%	4.50%	3.50%	3.50%	3.20%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	-$ 1,524,915	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B			
	Federal tax rate (Maximum 15%)	15.00%	C			
	Combined tax rate (Maximum 26.5%)				26.50%	D = B+C
Total Income Taxes					**-$ 404,102**	E = A * D
Investment Tax Credits					$ 7,821	F
Miscellaneous Tax Credits					-$ 135,865	G
Total Tax Credits					**-$ 128,044**	H = F + G
Corporate PILs/Income Tax Provision for Historical Year					$ -	I = E - H

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**(A + 101 + 102)**	6,237,202		6,237,202
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	6,316,605		6,316,605
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111	82,540		82,540
Charitable donations and gifts from Schedule 2	112	25,100		25,100
Taxable capital gains from Schedule 6	113			0
Political contributions	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118	282,931		282,931
Capitalized interest	119			0
Non-deductible club dues and fees	120	1,700		1,700
Non-deductible meals and entertainment expense	121	18,136		18,136
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements – balance at the end of the year	126	4,659,718		4,659,718
Soft costs on construction and renovation of buildings	127			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other additions				
Interest Expensed on Capital Leases	295			0
Realized Income from Deferred Credit Accounts	295			0
Pensions	295			0
Non-deductible penalties	295			0
	295			0
Inducement under ITA 12(1)(x)	295	20,064		20,064
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))		6,214,032		6,214,032
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))		9,948,532		9,948,532
Prior Year Investment Tax Credits received				0
Movement in Sch 13s reversed as part of OCI		496,500		496,500
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**28,065,858**	**0**	**28,065,858**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Non-taxable dividends under section 83	402			0

Ontario Energy Board

Income Tax/PILs Workforn for 2021 Filers

Adjusted Taxable Income - Historical Year

Capital cost allowance from Schedule 8	403	10,259,615		10,259,615
Terminal loss from Schedule 8	404			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411	222,744		222,744
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	5,100,343		5,100,343
Contributions to deferred income plans	416	197,131		197,131
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions				
Interest capitalized for accounting deducted for tax	395			0
Capital Lease Payments	395			0
Non-taxable imputed interest income on deferral and variance accounts	395			0
Non-taxable/deductible other comprehensive income items	395	364,934		364,934
	395			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received		6,214,032		6,214,032
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve		9,948,532		9,948,532
Principal portion of lease payments		197,224		197,224
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
Tax recovery incl. in net movements in reg. balance on P&L		1,336,746		1,336,746
Overhead capitalized for accounting		393,791		393,791
Amortization of deferred capital contributions		477,936		477,936
Net movement in regulatory balances		646,151		646,151
SR&ED cost capitalized for accounting		231,883		231,883
Reverse SR&ED credits booked in NI		97,754		97,754
Remove PPE item net movement in regulatory balances		139,159		139,159
Total Deductions		**35,827,975**	**0**	**35,827,975**
Net Income for Tax Purposes		**-1,524,915**	**0**	**-1,524,915**
Charitable donations from Schedule 2	311	0		0
Taxable dividends received under section 112 or 113	320			0
Non-capital losses of previous tax years from Schedule 4	331			0
Net capital losses of previous tax years from Schedule 4	332			0
Limited partnership losses of previous tax years from Schedule 4	335			0
TAXABLE INCOME		**-1,524,915**	**0**	**-1,524,915**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	85,869	0	85,869	B4

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Buildings, Distribution System (acq'd post 1987)	$ 53,569,263		$ 53,569,263
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	$ 1,957,188		$ 1,957,188
2	Distribution System (acq'd pre 1988)			$ -
3	Buildings (acq'd pre 1988)			$ -
6	Certain Buildings; Fences			$ -
8	General Office Equipment, Furniture, Fixtures	$ 1,836,113		$ 1,836,113
10	Motor Vehicles, Fleet	$ 771,674		$ 771,674
10.1	Certain Automobiles			$ -
12	Computer Application Software (Non-Systems)			$ -
13_1	Lease # 1			$ -
13_2	Lease # 2			$ -
13_3	Lease # 3			$ -
13_4	Lease # 4			$ -
14	Limited Period Patents, Franchises, Concessions or Licences			$ -
14.1	Eligible Capital Property (acq'd pre 2017)	$ 1,908,973		$ 1,908,973
14.1	Eligible Capital Property (acq'd post 2016)	$ 2,566,090		$ 2,566,090
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -
42	Fibre Optic Cable			$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	$ 85		$ 85
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -
47	Distribution System (acq'd post Feb 22/05)	$ 48,887,801		$ 48,887,801
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	$ 93,423		$ 93,423
95	CWIP	$ -		$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
				$ -
	SUB-TOTAL - UCC	111,590,610	0	111,590,610

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital gains reserves ss.40(1)			0
Tax reserves not deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & share issue expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General reserve for inventory obsolescence (non-specific)			0
General reserve for bad debts	170,000		170,000
Accrued Employee Future Benefits:	4,489,718		4,489,718
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**4,659,718**	**0**	**4,659,718**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	-$ 470,137	A
Ontario (Max 11.5%)	11.5%	11.5%	-$ 54,066	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	-$ 70,521	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							**$ -**	**E = A * D**
Investment Tax Credits							$ -	F
Miscellaneous Tax Credits							-$ 85,761	G
Total Tax Credits							**-$ 85,761**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 85,761**	**I = E - H**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**(A + 101 + 102)**		3,697,004
Additions:			
Interest and penalties on taxes	103		0
Amortization of tangible assets	104		7,228,644
Amortization of intangible assets	106		0
Recapture of capital cost allowance from Schedule 8	107	B8	0
Income inclusion under subparagraph 13(38)(d)(iii)	108		0
Income or loss for tax purposes- joint ventures or partnerships	109		0
Loss in equity of subsidiaries and affiliates	110		0
Loss on disposal of assets	111		
Charitable donations and gifts from Schedule 2	112		34,603
Taxable capital gains	113		0
Political contributions	114		0
Deferred and prepaid expenses	116		0
Scientific research expenditures deducted on financial statements	118		291,161
Capitalized interest	119		0
Non-deductible club dues and fees	120		1,700
Non-deductible meals and entertainment expense	121		18,136
Non-deductible automobile expenses	122		0
Non-deductible life insurance premiums	123		0
Non-deductible company pension plans	124		0
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	4,765,000
Soft costs on construction and renovation of buildings	127		0
Capital items expensed	206		0
Debt issue expense	208		0
Development expenses claimed in current year	212		0
Financing fees deducted in books	216		0
Gain on settlement of debt	220		0
Non-deductible advertising	226		0
Non-deductible interest	227		0
Non-deductible legal and accounting fees	228		0
Recapture of SR&ED expenditures	231		0
Share issue expense	235		0
Write down of capital property	236		0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Prior Year Credits (12(1)(x))			12,334
Additional accounting depreciation (ICM)			42,800
Total Additions			**12,394,378**
Deductions:			

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Gain on disposal of assets per financial statements	401		0
Dividends not taxable under section 83	402		0
Capital cost allowance from Schedule 8	403	B8	9,992,602
Terminal loss from Schedule 8	404	B8	0
Allowable business investment loss	406		0
Deferred and prepaid expenses	409		0
Scientific research expenses claimed in year	411		280,970
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	4,659,718
Contributions to deferred income plans	416		0
Book income of joint venture or partnership	305		0
Equity in income from subsidiary or affiliates	306		0
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		113,638
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Capitalized OH deducted for tax			517,572
SR&ED capitalized for accounting			258,337
Amortization of deferred capital contributions			738,682
Total Deductions		calculated	**16,561,519**
Net Income for Tax Purposes		calculated	**-470,137**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	B4	0
Net capital losses of previous tax years from Schedule 4	332	B4	0
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		calculated	**-470,137**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	470,137	
Other Adjustments			
Balance available for use post Bridge Year	calculated	470,137	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	85,869	
Amount to be used in Bridge Year		0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	0	
Other Adjustments		0	
Balance available for use post Bridge Year	calculated	85,869	T4

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 53,569,263							$ 53,569,263	$ -	$ -	0.50	$ -	$ -	4%			$ 2,142,771		$ 51,426,492	T8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ 1,957,188	$ 537,745	$ 537,745				$ -	$ 2,494,933	$ -	$ 537,745	0.50	$ 268,873	$ -	6%			$ 165,828		$ 2,329,105	T8
2	Distribution System (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -	T8
3	Buildings (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -	T8
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -	T8
8	General Office Equipment, Furniture, Fixtures	H8	$ 1,836,113	$ 61,551	$ 61,551				$ -	$ 1,897,664	$ -	$ 61,551	0.50	$ 30,776	$ -	20%			$ 385,688		$ 1,511,976	T8
10	Motor Vehicles, Fleet	H8	$ 771,674	$ 360,837	$ 360,837				$ -	$ 1,132,511	$ -	$ 360,837	0.50	$ 180,419	$ -	30%			$ 393,879		$ 738,632	T8
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
12	Computer Application Software (Non-Systems)	H8	$ -	$ 1,954,898	$ 1,954,898				$ -	$ 1,954,898	$ -	$ 1,954,898	0.00	$ -	$ -	100%			$ 1,954,898		$ -	T8
13_1	Lease # 1	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_2	Lease # 2	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_3	Lease # 3	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_4	Lease # 4	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ 1,908,973							$ 1,908,973	$ -	$ -		$ -	$ -	7%			$ 133,628		$ 1,775,345	T8
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ 2,566,090							$ 2,566,090	$ -	$ -	0.50	$ -	$ -	5%			$ 128,305		$ 2,437,786	T8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -	T8
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -	T8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -	T8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -	T8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ 85							$ 85	$ -	$ -		$ -	$ -	45%			$ 38		$ 47	T8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
47	Distribution System (acq'd post Feb 22/05)	H8	$ 48,887,801	$ 5,547,042	$ 5,547,042				$ -	$ 54,434,843	$ -	$ 5,547,042	0.50	$ 2,773,521	$ -	8%			$ 4,576,669		$ 49,858,174	T8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ 93,423	$ 72,140	$ 72,140				$ -	$ 165,563	$ -	$ 72,140	0.50	$ 36,070	$ -	55%			$ 110,898		$ 54,665	T8
95	CWIP	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
	TOTALS		$ 111,590,610	$ 8,534,213	$ 8,534,213	$ -	$ -	$ -	$ -	$ 120,124,823	$ -	$ 8,534,213		$ 3,289,658	$ -		$ -	$ -	$ 9,992,602	B1	$ 110,132,221	

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year		Change During the Year	Disallowed Expenses
Capital gains reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for Accounting Purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & share issue expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**	**0**
Financial statement reserves (not deductible for tax purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General Reserve for Bad Debts	H13	170,000		170,000		30,000		200,000	T13	30,000	
Accrued Employee Future Benefits:	H13	4,489,718		4,489,718		75,282		4,565,000	T13	75,282	
- Medical and Life Insurance	H13	0		0				0	T13	0	
- Short & Long-term Disability	H13	0		0				0	T13	0	
- Accumulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**4,659,718**	**0**	**4,659,718**	B1	**105,282**	**0**	**4,765,000**	B1	**105,282**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

PILs Tax Provision - Test Year

								Wires Only	
Regulatory Taxable Income							T1	$ 1,453,667	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 167,172	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 218,050	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								**$ 385,222**	E = A * D
Investment Tax Credits								$ 52,337	F
Miscellaneous Tax Credits								$ 39,933	G
Total Tax Credits								**$ 92,270**	H = F + G
Corporate PILs/Income Tax Provision for Test Year								**$ 292,952**	I = E - H S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	J = 1-D	**$ 105,622**	K = I/J-I
Income Tax (grossed-up)								**$ 398,574**	L = K + I S. Summary

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	4,913,439
Additions:			
Interest and penalties on taxes	103		0
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		8,103,753
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		0
Recapture of capital cost allowance from Schedule 8	107	T8	0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		0
Loss in equity of subsidiaries and affiliates	110		0
Loss on disposal of assets	111		98,000
Charitable donations	112		47,000
Taxable Capital Gains	113		0
Political Donations	114		0
Deferred and prepaid expenses	116		0
Scientific research expenditures deducted on financial statements	118		291,161
Capitalized interest	119		0
Non-deductible club dues and fees	120		1,700
Non-deductible meals and entertainment expense	121		18,136
Non-deductible automobile expenses	122		0
Non-deductible life insurance premiums	123		0
Non-deductible company pension plans	124		0
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	4,835,000
Soft costs on construction and renovation of buildings	127		0
Book loss on joint ventures or partnerships	205		0
Capital items expensed	206		0
Debt issue expense	208		0
Development expenses claimed in current year	212		0
Financing fees deducted in books	216		0
Gain on settlement of debt	220		0
Non-deductible advertising	226		0
Non-deductible interest	227		0
Non-deductible legal and accounting fees	228		0
Recapture of SR&ED expenditures	231		
Share issue expense	235		0
Write down of capital property	236		0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Prior Year Credits (12(1)(x))			14,058
Additional accounting depreciation (ICM)			42,800
Total Additions			**13,451,608**
Deductions:			
Gain on disposal of assets per financial statements	401		0
Dividends not taxable under section 83	402		0

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Taxable Income - Test Year

		Working Paper Reference	Test Year Taxable Income
Capital cost allowance from Schedule 8	403	T8	9,234,575
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		0
Deferred and prepaid expenses	409		0
Scientific research expenses claimed in year	411		280,970
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	4,765,000
Contributions to deferred income plans	416		0
Book income of joint venture or partnership	305		0
Equity in income from subsidiary or affiliates	306		0
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		73,855
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
Capitalized OH deducted for tax	395		583,427
SR&ED capitalized for accounting	395		258,337
Amortization of deferred capital contributions	395		1,198,080
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**16,394,244**
NET INCOME FOR TAX PURPOSES		calculated	**1,970,803**
Charitable donations	311		47,000
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	470,137
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,453,667**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	470,137		470,137
Amount to be used in Test Year and Price Cap Years	T1	470,137		470,137
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	470,137		470,137
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	85,869		85,869
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		85,869		85,869

Ontario Energy Board

Income Tax/PILs Workform for 2021 Filers

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 51,426,492							$ 51,426,492	$ -	$ -	0.50	$ -	$ -	4%
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ 2,329,105	$ 420,000	$ 420,000				$ -	$ 2,749,105	$ -	$ 420,000	0.50	$ 210,000	$ -	6%
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	6%
3	Buildings (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	5%
6	Certain Buildings; Fences	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%
8	General Office Equipment, Furniture, Fixtures	B8	$ 1,511,976	$ 51,500	$ 51,500				$ -	$ 1,563,476	$ -	$ 51,500	0.50	$ 25,750	$ -	20%
10	Motor Vehicles, Fleet	B8	$ 738,632	$ 75,000	$ 75,000				$ -	$ 813,632	$ -	$ 75,000	0.50	$ 37,500	$ -	30%
10.1	Certain Automobiles	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%
12	Computer Application Software (Non-Systems)	B8	$ -	$ 766,370	$ 766,370				$ -	$ 766,370	$ -	$ 766,370	0.00	$ -	$ -	100%
13_1	Lease # 1	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA
13_2	Lease # 2	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA
13_3	Lease # 3	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA
13_4	Lease # 4	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ 1,775,345							$ 1,775,345	$ -	$ -		$ -	$ -	7%
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ 2,437,786		0					$ 2,437,786	$ -	$ -	0.50	$ -	$ -	5%
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%
42	Fibre Optic Cable	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 47							$ 47	$ -	$ -		$ -	$ -	45%
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%
47	Distribution System (acq'd post Feb 22/05)	B8	$ 49,858,174	$ 11,285,497	$ 11,285,497				$ -	$ 61,143,671	$ -	$ 11,285,497	0.50	$ 5,642,749	$ -	8%
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 54,665	$ 50,000	$ 50,000				$ -	$ 104,665	$ -	$ 50,000	0.50	$ 25,000	$ -	55%
95	CWIP	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
		B8	$ -							$ -	$ -	$ -		$ -	$ -	
	TOTALS		$ 110,132,221	$ 12,648,367	$ 12,648,367	$ -	$ -	$ -	$ -	$ 122,780,588	$ -	$ 12,648,367		$ 5,940,999	$ -	

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Income Tax/PILs Workfo

Schedule 8 CCA - Test Year

(1) Class	Class Description	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)			$ 2,057,060		$ 49,369,433
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]			$ 177,546		$ 2,571,558
2	Distribution System (acq'd pre 1988)			$ -		$ -
3	Buildings (acq'd pre 1988)			$ -		$ -
6	Certain Buildings; Fences			$ -		$ -
8	General Office Equipment, Furniture, Fixtures			$ 317,845		$ 1,245,631
10	Motor Vehicles, Fleet			$ 255,340		$ 558,293
10.1	Certain Automobiles			$ -		$ -
12	Computer Application Software (Non-Systems)			$ 766,370		$ -
13_{1}	Lease # 1					$ -
13_{2}	Lease # 2					$ -
13_{3}	Lease # 3					$ -
13_{4}	Lease # 4					$ -
14	Limited Period Patents, Franchises, Concessions or Licences					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)			$ 124,274		$ 1,651,070
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)			$ 121,889		$ 2,315,896
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -		$ -
42	Fibre Optic Cable			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)			$ 21		$ 26
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)			$ 5,342,914		$ 55,800,757
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)			$ 71,316		$ 33,349
95	CWIP			$ -		$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
						$ -
	TOTALS	$ -	$ -	$ 9,234,575	T1	$ 113,546,014

Income Tax/PILs Workform for 2021 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

						Test Year Adjustments					
Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Test Year	Adjusted Utility Balance		Additions	Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0				0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	200,000		200,000				200,000		0	
Accrued Employee Future Benefits:	B13	4,565,000		4,565,000		70,000		4,635,000		70,000	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**4,765,000**	**0**	**4,765,000**	T1	**70,000**	**0**	**4,835,000**	T1	**70,000**	**0**

Appendix E
Cost Allocation Model

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Sheet I6.1 Revenue Worksheet - Initial Model Preparation

Total kWhs from Load Forecast	1,547,456,800

Total kWs from Load Forecast	2,350,199

Deficiency/sufficiency (RRWF 8. cell F51)	- 2,072,057

Miscellaneous Revenue (RRWF 5. cell F48)	3,079,167

			1	2	5	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS >50-Intermediate**	**Street Light**	**Unmetered Scattered Load**
Billing Data							
Forecast kWh	**CEN**	1,547,456,800	520,340,552	168,693,830	849,749,403	5,569,644	3,103,371
Forecast kW	**CDEM**	2,350,199			2,334,671	15,528	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		883,054			883,054		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	1,547,456,800	520,340,552	168,693,830	849,749,403	5,569,644	3,103,371
Existing Monthly Charge			$26.51	$27.06	$63.44	$0.65	$9.73
Existing Distribution kWh Rate				$0.0145			$0.0169
Existing Distribution kW Rate					$3.1231	$4.7037	
Existing TOA Rate					$0.60		
Additional Charges							
Distribution Revenue from Rates		$32,374,800	$19,741,165	$4,252,955	$8,055,675	$207,849	$117,157
Transformer Ownership Allowance		$529,832	$0	$0	$529,832	$0	$0
Net Class Revenue	**CREV**	$31,844,968	$19,741,165	$4,252,955	$7,525,842	$207,849	$117,157

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Sheet I6.2 Customer Data Worksheet - Initial Model Preparation

	ID	Total	1 Residential	2 GS <50	5 GS >50-Intermediate	7 Street Light	9 Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$278,510	$105,733	$50,342	$122,435	$0	$0
Late Payment 3 Year Historical Average	LPHA	$199,940	$99,112	$28,491	$72,161	$117	$60
Number of Bills	CNB	9,015,168	744,669	66,774	12,047	36	288
Number of Devices	CDEV					17,283	554
Number of Connections (Unmetered)	CCON	2,283				1,728	554
Total Number of Customers	CCA	68,651	62,056	5,564	1,004	3	24
Bulk Customer Base	CCB	68,651	62,056	5,564	1,004	3	24
Primary Customer Base	CCP	69,214	62,056	5,564	1,004	565	24
Line Transformer Customer Base	CCLT	69,064	62,056	5,514	905	565	24
Secondary Customer Base	CCS	68,497	62,056	5,514	900	3	24
Weighted - Services	CWCS	65,510	62,056	2,760	-	164	530
Weighted Meter -Capital	CWMC	22,933,375	14,238,745	5,013,544	3,681,086	-	-
Weighted Meter Reading	CWMR	86,620	65,293	5,564	15,763	-	-
Weighted Bills	CWNB	974,861	744,669	105,797	124,135	22	238

Bad Debt Data

		Total	Residential	GS <50	GS >50-Intermediate	Street Light	Unmetered Scattered Load
Historic Year:	2017	203,269	130,784	57,472	15,013		
Historic Year:	2018	469,922	89,631	51,666	328,625		
Historic Year:	2019	162,339	96,786	41,887	23,667		
Three-year average		**278,510**	**105,733**	**50,342**	**122,435**	**-**	**-**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	62,056	604,459	62,056	604,459
Street Light	17,283	5,508	17,283	5,508

Street Lighting Adjustment Factors	
Primary	30.5648
Line Transformer	30.5648

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Sheet I8 Demand Data Worksheet - Initial Model Preparation

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	5 GS >50- Intermediate	7 Street Light	9 Unmetered Scattered Load
		CP Sanity Check	Pass	Pass	Pass	Check 12CP	Check 4CP and 12CP
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	321,264	139,606	39,836	141,475	-	347
Bulk Delivery CP	BCP1	321,264	139,606	39,836	141,475	-	347
Total Sytem CP	DCP1	321,264	139,606	39,836	141,475	-	347
4 CP							
Transformation CP	TCP4	1,238,772	527,114	148,321	561,926	-	1,411
Bulk Delivery CP	BCP4	1,238,772	527,114	148,321	561,926	-	1,411
Total Sytem CP	DCP4	1,238,772	527,114	148,321	561,926	-	1,411
12 CP							
Transformation CP	TCP12	3,038,484	1,195,637	355,975	1,477,067	5,549	4,255
Bulk Delivery CP	BCP12	3,038,484	1,195,637	355,975	1,477,067	5,549	4,255
Total Sytem CP	DCP12	3,038,484	1,195,637	355,975	1,477,067	5,549	4,255
NON CO_INCIDENT PEAK							
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass
1 NCP							
Classification NCP from Load Data Provider	DNCP1	351,052	160,581	40,066	148,573	1,448	384
Primary NCP	PNCP1	351,052	160,581	40,066	148,573	1,448	384
Line Transformer NCP	LTNCP1	292,354	160,581	39,458	90,483	1,448	384
Secondary NCP	SNCP1	291,938	160,581	39,458	90,067	1,448	384
4 NCP							
Classification NCP from Load Data Provider	DNCP4	1,353,817	604,459	154,179	588,212	5,508	1,459
Primary NCP	PNCP4	1,353,817	604,459	154,179	588,212	5,508	1,459
Line Transformer NCP	LTNCP4	1,121,495	604,459	151,842	358,227	5,508	1,459
Secondary NCP	SNCP4	1,119,848	604,459	151,842	356,580	5,508	1,459
12 NCP							
Classification NCP from Load Data Provider	DNCP12	3,370,419	1,375,972	390,535	1,584,135	15,523	4,255
Primary NCP	PNCP12	3,370,419	1,375,972	390,535	1,584,135	15,523	4,255
Line Transformer NCP	LTNCP12	2,745,117	1,375,972	384,614	964,754	15,523	4,255
Secondary NCP	SNCP12	2,740,682	1,375,972	384,614	960,318	15,523	4,255

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Sheet O1 Revenue to Cost Summary Worksheet - Initial Model Preparation

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	5	7	9
Rate Base Assets		Total	Residential	GS <50	GS >50-Intermediate	Street Light	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$31,844,968	$19,741,165	$4,252,955	$7,525,842	$207,849	$117,157
mi	Miscellaneous Revenue (mi)	$3,079,167	$1,957,779	$334,713	$763,564	$15,319	$7,792
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	**$34,924,135**	**$21,698,944**	**$4,587,668**	**$8,289,406**	**$223,168**	**$124,949**
	Factor required to recover deficiency (1 + D)	1.0651					
	Distribution Revenue at Status Quo Rates	$33,917,025	$21,025,663	$4,529,682	$8,015,526	$221,373	$124,780
	Miscellaneous Revenue (mi)	$3,079,167	$1,957,779	$334,713	$763,564	$15,319	$7,792
	Total Revenue at Status Quo Rates	**$36,996,192**	**$22,983,443**	**$4,864,395**	**$8,779,090**	**$236,692**	**$132,572**
	Expenses						
di	Distribution Costs (di)	$8,620,000	$5,069,942	$882,407	$2,600,742	$40,366	$26,543
cu	Customer Related Costs (cu)	$3,766,440	$2,768,139	$448,821	$538,580	$7,810	$3,090
ad	General and Administration (ad)	$8,513,125	$5,385,771	$915,800	$2,157,098	$33,675	$20,781
dep	Depreciation and Amortization (dep)	$8,146,553	$5,070,779	$976,831	$2,036,265	$38,615	$24,062
INPUT	PILs (INPUT)	$398,574	$249,630	$44,152	$101,436	$2,057	$1,299
INT	Interest	$2,638,061	$1,652,239	$292,232	$671,377	$13,615	$8,597
	Total Expenses	**$32,082,753**	**$20,196,501**	**$3,560,242**	**$8,105,497**	**$136,139**	**$84,373**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$4,913,439	$3,077,328	$544,287	$1,250,453	$25,358	$16,013
	Revenue Requirement (includes NI)	$36,996,192	$23,273,829	$4,104,530	$9,355,951	$161,497	$100,385
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$343,324,891	$218,367,778	$37,200,453	$84,865,554	$1,720,274	$1,170,832
gp	General Plant - Gross	$45,507,606	$29,222,979	$4,765,093	$11,119,731	$236,423	$163,379
accum dep	Accumulated Depreciation	($177,259,444)	($111,229,551)	($19,948,613)	($44,656,184)	($859,104)	($565,992)
co	Capital Contribution	($79,296,392)	($53,230,199)	($7,473,048)	($17,847,669)	($414,301)	($331,175)
	Total Net Plant	**$132,276,661**	**$83,131,007**	**$14,543,885**	**$33,481,432**	**$683,292**	**$437,044**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$179,216,197	$60,531,331	$19,524,642	$98,158,365	$643,375	$358,484
	OM&A Expenses	$20,899,565	$13,223,853	$2,247,028	$5,296,420	$81,851	$50,414
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	***$200,115,762***	***$73,755,184***	***$21,771,669***	***$103,454,785***	***$725,226***	***$408,898***
	Working Capital	**$15,008,682**	**$5,531,639**	**$1,632,875**	**$7,759,109**	**$54,392**	**$30,667**
	Total Rate Base	**$147,285,343**	**$88,662,646**	**$16,176,761**	**$41,240,540**	**$737,684**	**$467,712**
		Rate Base Input equals Output					
	Equity Component of Rate Base	**$58,914,137**	**$35,465,058**	**$6,470,704**	**$16,496,216**	**$295,074**	**$187,085**
	Net Income on Allocated Assets	**$4,913,439**	**$2,786,942**	**$1,304,153**	**$673,593**	**$100,553**	**$48,199**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$4,913,439**	**$2,786,942**	**$1,304,153**	**$673,593**	**$100,553**	**$48,199**
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**98.75%**	**118.51%**	**93.83%**	**146.56%**	**132.06%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($2,072,057)	($1,574,885)	$483,138	($1,066,544)	$61,671	$24,563
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($290,386)	$759,865	($576,860)	$75,195	$32,186
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.34%	7.86%	20.15%	4.08%	34.08%	25.76%

EB-2020-0007

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Model Preparation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	5	7	9
	Residential	GS <50	GS >50-Intermediate	Street Light	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$3.82	$9.15	$39.48	$0.36	$0.41
Customer Unit Cost per month - Directly Related	$5.92	$13.16	$62.04	$0.62	$0.71
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.74	$25.32	$95.84	$4.17	$11.77
Existing Approved Fixed Charge	$26.51	$27.06	$63.44	$0.65	$9.73

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	5	7	9
	Total	Residential	GS <50	GS >50-Intermediate	Street Light	Unmetered Scattered Load
General Plant - Gross Assets	$45,507,606	$29,222,979	$4,765,093	$11,119,731	$236,423	$163,379
General Plant - Accumulated Depreciation	($27,521,477)	($17,673,080)	($2,881,769)	($6,724,842)	($142,980)	($98,806)
General Plant - Net Fixed Assets	$17,986,128	$11,549,899	$1,883,324	$4,394,890	$93,442	$64,573
General Plant - Depreciation	$2,229,507	$1,431,691	$233,451	$544,777	$11,583	$8,004
Total Net Fixed Assets Excluding General Plant	$114,290,532	$71,581,108	$12,660,561	$29,086,542	$589,850	$372,471
Total Administration and General Expense	$8,513,125	$5,385,771	$915,800	$2,157,098	$33,675	$20,781
Total O&M	$12,386,440	$7,838,081	$1,331,227	$3,139,322	$48,177	$29,633

SCHEDULE C

DECISION AND RATE ORDER

ACCOUNTING ORDERS

BURLINGTON HYDRO INC.

EB-2020-0007

APRIL 15, 2021

Accounting Order #1
Burlington Hydro Inc.
EB-2020-0007

Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account

Effective May 1, 2021, BHI shall establish a new variance account: Account 1508 Sub-account - Capital Additions Dundas Street Road Widening Project - Revenue Requirement Differential Variance Account ("CVA1"). The purpose of this sub-account is to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Dundas Street Road Widening Project and the resulting impact during the IRM period. If the revenue requirement impact is lower than forecast in the 2021 Test Year, (budgeted net capital additions in the 2021 Test Year exceed actual net capital additions), BHI will make a credit entry in the applicable variance account representing a refund to ratepayers. This is an asymmetrical account and as such, if the revenue requirement impact is higher than forecast in the 2021 Test Year, (actual capital additions in the 2021 Test Year exceed budgeted capital additions), no entry will be made to the variance account. 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 Plan shall be used, which is consistent with the treatment of the CCA on the capital additions in the 2021 Test Year. All components of cost of capital will use the weighted average cost of debt and return on equity %, and capital structure, as approved in BHI's Cost of Service Application EB-2020-0007.

If the budgeted net capital additions in the 2021 Test Year exceed actual net capital additions, for each rate year from 2022 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2021 Test Year associated with the difference between budgeted and actual net capital additions, escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year.

The variance account will be disposed at BHI's next rebasing application, if applicable, as per the OEB's guidelines related to Group 2 Accounts. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries for underspending on the Dundas Street Road Widening Project in the 2021 Test Year and IRM years. (i.e., actual net capital additions are less than budgeted net capital additions).

	Debit	Credit
DR. Account 4080 - Distribution Services Revenue	x,xxx.xx	
CR. Account 1508 - Sub-account CVA1 – Depreciation		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – Deemed Interest Expense		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – Return on Equity		x,xxx.xx
CR. Account 1508 - Sub-account CVA1 – PILs		x,xxx.xx
DR. Account 6035 - Interest Expense	x,xxx.xx	
CR. Account 1508 - Sub-account CVA1 – Carrying Charges		x,xxx.xx

Accounting Order #2
Burlington Hydro Inc.
EB-2020-0007

Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account

Effective May 1, 2021, BHI shall establish a new variance account: Account 1508 Sub-account - Capital Additions Waterdown Rd Road Widening Project - Revenue Requirement Differential Variance Account ("CVA2"). The purpose of this sub-account is to record the revenue requirement associated with the difference between budgeted and actual capital additions, net of capital contributions, in the 2021 Test Year for the Waterdown Rd Road Widening Project and the resulting impact during the IRM period. If the revenue requirement impact is lower than forecast in the 2021 Test Year, (budgeted net capital additions in the 2021 Test Year exceed actual net capital additions), BHI will make a credit entry in the applicable variance account representing a refund to ratepayers. This is an asymmetrical account and as such, if the revenue requirement impact is higher than forecast in the 2021 Test Year, (actual capital additions in the 2021 Test Year exceed budgeted capital additions), no entry will be made to the variance account. 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 Plan shall be used, which is consistent with the treatment of the CCA on the capital additions in the 2021 Test Year. All components of cost of capital will use the weighted average cost of debt and return on equity %, and capital structure, as approved in BHI's Cost of Service Application EB-2020-0007.

If the budgeted net capital additions in the 2021 Test Year exceed actual net capital additions, for each rate year from 2022 until BHI's next rebasing, BHI will make further entries into the account equal to the revenue requirement impact in the 2021 Test Year associated with the difference between budgeted and actual net capital additions, escalated annually by the OEB Price Cap IR annual adjustment (Inflation minus X-factor) in effect for that year.

The variance account will be disposed at BHI's next rebasing application, if applicable, as per the OEB's guidelines related to Group 2 Accounts. This account will accrue carrying charges at OEB-prescribed rates until final disposition.

The following are sample journal entries for underspending on the Waterdown Rd Road Widening Project in the 2021 Test Year and IRM years. (i.e., actual net capital additions are less than budgeted net capital additions).

	Debit	Credit
DR. Account 4080 - Distribution Services Revenue	x,xxx.xx	
CR. Account 1508 - Sub-account CVA2 – Depreciation		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – Deemed Interest Expense		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – Return on Equity		x,xxx.xx
CR. Account 1508 - Sub-account CVA2 – PILs		x,xxx.xx
DR. Account 6035 - Interest Expense	x,xxx.xx	
CR. Account 1508 - Sub-account CVA2 – Carrying Charges		x,xxx.xx