Burlington**hydro** inc.

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

October 10, 2019

Dear Ms. Walli,

Re: Electricity Distribution License ED-2003-0004
2020 IRM Application for Electricity Distribution Rates (EB-2019-0023)

Burlington Hydro Inc. ("Burlington Hydro") is submitting its sixth Electricity Distribution Rates application under the Fourth Generation Incentive Rate-Setting Mechanism ("Price Cap IR") to the Ontario Energy Board ("OEB") for electricity distribution rates and other charges effective May 1, 2020.

The Filing includes the Application; the Manager's Summary; and live versions of the following models or files:

1. 2020 IRM Rate Generator Model
2. GA Analysis Workform
3. 1595 Analysis Workform
4. LRAMVA Workform
5. 2017 Final Verified Annual LDC CDM Program Results Report – June 2018
6. 2017 Final Verified Annual LDC CDM Program Results Project List – June 2018
7. Participation and Cost Report – April 2019
8. Summary Streetlight Upgrade Project
9. 2020 ICM Module
10. Tremaine CCRA ICM Module
11. 2020 IRM Checklist

The Filing and supporting materials are being filed through the OEB's RESS system; two hard copies will follow by courier.

Yours truly,

Original Signed by

Sally Blackwell
Vice President, Regulatory Compliance & Asset Management
Email: sblackwell@burlingtonhydro.com
Tel: 905-336-4373

Attachments

1340 Brant Street, Burlington, ON · L7R 3Z7 **burlingtonhydro.com** 905·332·1851

EB-2019-0023

IN THE MATTER OF the *Ontario Energy Board Act,* 1998, being Schedule B to the *Energy Competition Act,* 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Burlington Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2020.

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BURLINGTON HYDRO INC.

2020 RATE APPLICATION UNDER THE FOURTH GENERATION INCENTIVE RATE-SETTING MECHANISM ("PRICE CAP IR")

FILED: October 10, 2019

Applicant

Burlington Hydro Inc.
1340 Brant Street
Burlington, Ontario
L7R 3Z7
Website: www.burlingtonhydro.com

Sally Blackwell
Vice President, Regulatory Compliance & Asset Management
Tel: (905) 336-4373
Email: sblackwell@burlingtonhydro.com

Table of Contents

APPLICATION

1. Burlington Hydro Inc. ("Burlington Hydro" or "the Applicant") is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the City of Burlington, Ontario.

2. Burlington Hydro carries on the business of distributing electricity to approximately 67,000 customers within the City of Burlington pursuant to Electricity Distribution License No. ED-2003-0004 issued by the Ontario Energy Board ("OEB" or "Board").

3. Pursuant to Section 78 of the Ontario Energy Board Act, 1998, Burlington Hydro seeks an order or orders of the Board establishing distribution rates and other charges, effective May 1, 2020, including disposition of amounts accumulated in certain Deferral and Variance Accounts, as identified on page 12.

4. This application (the "Application") is prepared in accordance with: the OEB's *Filing Requirements for Electricity Distribution Rate Applications, 2018 Edition for 2019 Rate Applications – Chapter 3 Incentive Rate-Setting Applications*, dated July 12, 2018 and the *Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications dated July 15, 2019*; *Revision 4.0 of the Guideline G-2008-0001 – Electricity Distribution Retail Transmission Service Rates*, dated June 28, 2012; the July 31, 2009 *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (the "EDDVAR Report"); the letter from the Board dated May 23, 2017 re: Guidance on Disposition of Accounts 1588 and 1589; and is supported by written evidence that may be amended from time to time, prior to the Board's final decision on this Application.

Burlington Hydro has completed the 2020 IRM Check List, filed as Attachment 11_2020 IRM Check List_BHI_20191010.

5. Burlington Hydro has calculated its distribution rates and other charges using the Board's 2020 IRM Rate Generator Model – Version 2.0 updated on August 8, 2019. This model is filed as a live excel file: Attachment 1_2020 IRM Model_BHI_20191010.

Relief Requested

6. Burlington Hydro requests the following relief:

    1. Approval for an Order or Orders approving the Tariff of Rates and Charges set out in Appendix B of this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2020.
    2. Approval of updated Retail Transmission Service Rates ("RTSRs"), as identified on page 10.
    3. Approval for the clearance of the balances recorded in certain deferral and variance accounts by means of class-specific rate riders effective May 1, 2020 to April 30, 2021, as identified on page 21.
    4. Approval for the clearance of the balance in its Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") resulting from its Conservation and Demand Management ("CDM") activities as of December 31, 2018 as identified on page 35.
    5. Approval for incremental capital funding and associated rate riders effective May 1, 2020 until the next rebasing application as identified on page 43.
    6. Approval to revise the effective end date of its current Rate Rider for Recovery of Incremental Capital Project 1 (2019) to April 30, 2020 as identified on page 56.

Proposed Effective Date of Rate Order

7. Burlington Hydro proposes that the Board make its Rate Order effective May 1, 2020. The proposed Tariff of Rates and Charges is provided as Appendix B.
8. Burlington Hydro requests that its current (i.e., 2019) rates provided in Appendix A be declared interim effective May 1, 2020, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2020; and that it be permitted to establish an account to recover any differences between the interim rates and the actual rates effective May 1, 2020 based on the OEB's Decision and Order.

Certification of Evidence

9. Burlington Hydro provides a Certification of Evidence as Appendix C.

Form of Hearing Requested

10. Burlington Hydro requests that this Application be disposed of by way of a written hearing.

Status of Board Directives from Previous Board Decisions

2018 IRM Application (EB-2017-0029)

11. Burlington Hydro has one directive from the Board based on the Board Decision for its 2019 IRM Application (EB-2018-0021):

a. The OEB directs Burlington Hydro to record the OEB tax sharing amount of $29,784 in variance Account 1595 for disposition at a future date[1]. Burlington Hydro recorded the tax sharing amount in variance account 1595 in June 2019.

Website Address

12. Burlington Hydro's website address is www.burlingtonhydro.com

Contact Information

13. Burlington Hydro requests that all documents filed with the OEB in this proceeding be served on the undersigned.

All of which is respectfully submitted this 10th day of October, 2019.

Sally Blackwell
Vice President, Regulatory Compliance & Asset Management
Burlington Hydro Inc.
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[1] Decision and Order EB-2018-0021, page 5

Manager's Summary

Burlington Hydro filed a Cost of Service ("CoS") application (EB-2013-0115) with the Board on October 1, 2013 under Section 78 of the OEB Act seeking approval for changes to the rates that Burlington Hydro charges for electricity distribution effective May 1, 2014. The OEB issued its Decision and Rate Order on May 15, 2014 which resulted in final distribution rates for 2014. Burlington Hydro subsequently filed four applications under the Fourth Generation Incentive Rate-Setting Mechanism ("Price Cap IR"), for distribution rates and other charges effective May 1, 2015, 2016, 2017 and 2018.

Burlington Hydro was scheduled to file a CoS application with the Board for distribution rates effective May 1, 2019. On February 1, 2018, Burlington Hydro requested a one-year deferral to file this CoS application. The OEB approved this request on August 14, 2018 and Burlington Hydro filed a Price Cap IR application (EB-2018-0021) on September 24, 2018. On February 20, 2019, Burlington Hydro requested another one-year deferral to file its CoS application. The OEB approved this request on July 5, 2019 and indicated that if Burlington Hydro intended to seek a rate adjustment for 2020 rates, that it expected Burlington Hydro to set distribution rates and other charges under the Price Cap IR.

Burlington Hydro is now seeking approval to set distribution rates and other charges under the Price Cap IR, to be effective May 1, 2020. This Application is Burlington Hydro's sixth Electricity Distribution Rates application under the Price Cap IR.

Burlington Hydro has completed the 2020 IRM Rate Generator Model – Version 2.0 updated on August 8, 2019 ("the IRM Model") by the Board. This Application has been prepared in accordance with the *OEB's Filing Requirements for Electricity Distribution Rate Applications, 2018 Edition for 2019 Rate Applications – Chapter 3 Incentive Rate-Setting Applications,* dated July 12, 2018 (the "Chapter 3 Filing Requirements") including the key OEB reference documents listed therein; and the *Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications* dated July 15, 2019 (the "Addendum to the Filing Requirements"); and other guidelines and directions from the Board.

A detailed explanation of the rate adjustments is set out below on pages 7 to 57.

Electronic Models

Burlington Hydro has calculated its distribution rates and other charges using the IRM Model; and confirms that the billing determinants pre-populated in this model are accurate. Table 1 below provides Burlington Hydro's actual 2018 load data, in kWh and kW, by customer class; this data is not loss adjusted.

Table 1 – 2018 Consumption and Demand by Rate Class

Rate Class	2018 Consumption and Demand	
	Non-Uplifted kWh	kW
RESIDENTIAL	535,270,676	-
GENERAL SERVICE LESS THAN 50 kW	173,151,275	-
GENERAL SERVICE 50 TO 4,999 kW	878,675,189	2,378,408
UNMETERED SCATTERED LOAD	3,138,760	-
STREET LIGHTING	7,400,916	20,571
TOTAL	**1,597,636,816**	**2,398,979**

Price Cap IR Annual Adjustment

The annual adjustment follows an OEB-approved formula that includes components for inflation and the OEB's expectations of efficiency and productivity gains. The components in the formula are approved by the OEB annually. The formula is an inflation minus *X-factor* rate adjustment.

Inflation Factor

In its Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors the OEB adopted a 2-factor industry-specific price index methodology. The inflation factor is based on two weighted price indicators (labour and non-labour) which provide an input price that reflects Ontario's electricity industry.

Burlington Hydro has used the inflation factor populated in the IRM model by the Board which represents the Board's 2018 inflation factor of 1.2%, issued by the OEB on November 23, 2017. (i.e. Burlington Hydro notes that the Board did not use the 2019 inflation factor of 1.5%; however it is unable to change the value in the IRM model). Burlington Hydro will make a subsequent update for the 2020 inflation factor which is expected to be available prior to the Board rendering its Decision on this Application.

X-Factor

The X-factor has two parts: a productivity factor and a stretch factor. The OEB has determined that the appropriate value for the productivity factor (industry total factor productivity) for the Price Cap IR and Annual IR Index is zero. For the stretch factor, distributors are assigned into one of five groups ranging from 0.0% to 0.6%. Burlington Hydro was assigned to Group 2, corresponding to a stretch factor of 0.15% as identified in the OEB's *2018 Benchmarking Update,* dated August 2019. Therefore, the X-factor to be deducted from the inflation factor is 0.15%; and the annual adjustment to be applied to Burlington Hydro's rates is 1.05% as identified in Table 2 below:

Table 2 - Annual Adjustment to Distribution Rates

Factor	%
Inflation Factor	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.15%
Annual Adjustment	**1.05%**

Distribution Rates

The annual adjustment mechanism applies to distribution rates (fixed and variable charges) uniformly across customer rate classes and is applied to Burlington Hydro's current Board approved rates. Burlington Hydro seeks Board approval for the proposed distribution rates identified in Table 3 below, effective May 1, 2020. The residential rates reflect the final transition to fixed rates. This transition is discussed in further detail below. The derivation of Burlington Hydro's proposed 2020 Electricity Distribution Rates is provided in Tab "16. Rev2Cost_GDPIPI" of the IRM Model.

Table 3 – 2019 Board Approved and 2020 Proposed Distribution Rates

Rate Class	2019 Board Approved Distribution Rates		Annual Adjustment	2020 Proposed Distribution Rates	
	Fixed Charge	Variable Charge		Fixed Charge	Variable Charge
RESIDENTIAL	$26.03	$0.0000	1.05%	$26.30	$0.0000
GENERAL SERVICE LESS THAN 50 kW	$26.57	$0.0142	1.05%	$26.85	$0.0143
GENERAL SERVICE 50 TO 4,999 kW	$62.29	$3.0664	1.05%	$62.94	$3.0986
UNMETERED SCATTERED LOAD	$9.55	$0.0166	1.05%	$9.65	$0.0168
STREET LIGHTING	$0.64	$4.6183	1.05%	$0.65	$4.6668

Revenue-to-Cost Ratio Adjustments

The Revenue-to-Cost Ratios approved by the Board in Burlington Hydro's last CoS application (EB-2013-0115) were within the Board's target ranges; therefore Burlington Hydro is not applying for any adjustments to its Revenue-to-Cost Ratios in this Application.

Rate Design for Residential Electricity Customers

On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Electricity Customers* (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year transition period commencing in 2016 and ending in 2019.

The Board directed that "Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral."

Burlington Hydro incorporated the first, second, third and fourth year transition adjustments in its 2016, 2017, 2018 and 2019 rates respectively; and has completed the transition to a fully fixed monthly distribution service charge for residential customers.

Electricity Distribution Retail Transmission Service Rates

Burlington Hydro seeks Board approval for its proposed RTSRs as identified in Table 4 below. The proposed RTSRs were computed using the Board approved methodology in Tabs 10 to 15 of the IRM Model; and the OEB's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates (RTSR), Revision 4.0*, issued June 28, 2012; The IRM Model incorporates the most recent Hydro One Uniform Transmission Rates ("UTRs") approved by the OEB. The Board approved UTRs are identified in Table 5 below.

Table 4 – 2019 Approved and 2020 Proposed RTSRs

Rate Class	$ Per	2019 Board Approved		2020 Proposed RTSRs	
		Network	Connection	Network	Connection
RESIDENTIAL	kWh	0.0071	0.0064	0.0076	0.0068
GENERAL SERVICE LESS THAN 50 kW	kWh	0.0068	0.0057	0.0073	0.0061
GENERAL SERVICE 50 TO 4,999 kW	kW	2.8046	2.4996	2.9906	2.6704
UNMETERED SCATTERED LOAD	kWh	0.0068	0.0057	0.0073	0.0061
STREET LIGHTING	kW	2.0496	1.7789	2.1855	1.9005

Table 5 – Current Board Approved UTRs

Uniform Transmission Rates	$/kWh
Network	$3.83
Line Connection	$0.96
Transformation Connection	$2.30

Other Rates and Charges

Burlington Hydro is not seeking Board approval to change any of the rates or charges set out in the list below and proposes that the currently approved rates and charges apply throughout the 2020 rate year; with the exception of any rates which require updating subsequent to the submission of this application, as directed by the OEB.

- Smart Metering Entity Charge;
- Transformer Ownership Allowance;
- Primary Metering Allowance;
- Retail Service Charges;
- Specific Service Charges;
- Wholesale Market Service Charge;
- Rural and Remote Rate Protection;
- Standard Supply Service Administrative charge;
- Capacity Based Recovery;
- microFIT service charge;
- Loss Factor

Disposition of Group 1 Deferral and Variance Account Balances

Burlington Hydro seeks Board approval to dispose of the balances of Group 1 deferral and variance accounts on a final basis as at December 31, 2018, including interest to April 30, 2020. As discussed in the *Report of the Board on the Electricity Distributors' Deferral and Variance Account Review Initiative* (EB-2008-0046), (the "EDDVAR Report"), issued July 31, 2009, under the Price Cap IR or the Annual IR Index, the distributor's Group 1 account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is met; subject to an initiative announced by the OEB on July 20, 2018, discussed below. Consistent with a letter from the Board on July 25, 2014, distributors may also elect to dispose of Group 1 account balances below the threshold.

On July 20, 2018, the OEB issued a letter *"OEB's Plan to Standardize Processes to Improve Accuracy of Commodity Pass-Through Variance Accounts"* in which it announced an initiative to standardize the accounting processes used by distributors relating to Regulated Price Plan ("RPP") wholesale settlements and accounting procedures (including the treatment of unbilled revenue) to improve the accuracy of the Retail Settlement Variance Accounts: $RSVA_{POWER}$ and $RSVA_{GA}$. The OEB stated that it would not approve Group 1 rate riders on a final basis pending the development of this further guidance. Whether the riders will be approved on an interim basis or not approved at all (i.e. no disposition of account balances) would be determined on a case by case basis, until such time as the OEB finalized the new standardized requirements for regulatory accounting and RPP settlements.

On February 21, 2019, the OEB finalized the new standardized requirements for regulatory accounting and RPP settlements and issued its letter entitled "*Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment"* as well as the related accounting guidance. The accounting guidance is effective January 1, 2019 and is to be implemented by August 31, 2019.

Burlington Hydro applied for disposition of its 2017 Group 1 deferral and variance account balances in its 2019 IRM Application EB-2018-0021. The 2017 balance for Burlington Hydro's Group 1 accounts including interest projected to April 30, 2019 was a debit of $3,021,456. This included a recovery from customers of $3,192,019 and $1,683,555 in Accounts 1588 and 1589 respectively.

Any variance accumulated within Account 1588 should be settled directly with the IESO on a monthly basis and therefore any remaining amounts in this account should be relatively small and close to zero. Based on this expectation, OEB staff submitted that Burlington Hydro's balance in Account 1588 of $3.2M appeared to be unusually large. Burlington Hydro agreed and requested additional time to provide evidence, including calculations, to support the balances and agreed to undertake a full review of Accounts 1588 and 1589. It withdrew its request to dispose of its Group 1 balances in its 2019 IRM application.[2]

Subsequent to the OEB's Decision and Rate Order for EB-2018-0021, Burlington Hydro undertook a full review of Accounts 1588 and 1589 and identified the source of the large balance in Account 1588 as follows and as identified in Table 6 below:

- Cost of Power unbilled revenue was over-accrued in 2016 by $911k; this reversed in 2017 and is included in the 2017 balance requested for disposition; and
- kWh were allocated to "pre" Fair Hydro Plan Time-of-Use and Tiered buckets for the purposes of calculating the RPP vs. Market Price Claim in error, instead of to Fair Hydro Plan Time-of-Use and Tiered buckets; this overstated the revenue collected from customers for the purposes of calculating the RPP vs. Market Price Claim and incorrectly (i) understated the amount recoverable from the IESO and (ii) overstated the amount recoverable from customers by $2.1M. Burlington Hydro recovered this amount

[2] p 6-7, Decision and Rate Order EB-2018-0021

from the IESO in 2019, the transaction was recorded in 2019 in Burlington Hydro's financial statements (i.e. the debit balance in Account 1588 was reduced by $2.1M) and Burlington Hydro has adjusted Tab 3. Continuity Schedule in the IRM Model by this amount.

Both of these errors impacted Account 1588/Cost of Power only; there was no impact to Account 1589/Global Adjustment.

Table 6 – 2017 Correction to Account 1588

Description	2017	Comments
Reported Balance in Account 1588	**$3,121,991**	
Cost of Power Unbilled Revenue Over Accrued in 2016	($911,135)	no adjustment made - included in 2017 disposition balance
kWh assigned to pre-FHP RPP buckets	($2,173,966)	adjustment made/recovery from IESO in 2019
Balance in Account 1588 after adjustments	**$36,891**	

In the Addendum to the Filing Requirements, the OEB stated its expectation that "*Distributors are expected to consider the accounting guidance in the context of historical balances that have yet to be disposed on a final basis (including the 2018 balances that may be requested for disposition in* its *rate application)".*

The OEB also identified its expectation of final disposition requests of commodity pass through accounts in the case where "*no disposition of historical balances and concerns noted*" as follows:

> *"Utilities that did not receive approval for disposition of historical account balances due to concerns noted should apply the accounting guidance to those balances as well as the 2018 balance and adjust the balances as necessary, prior to requesting final disposition".*

As previously stated, Burlington Hydro undertook a full review of Accounts 1588 and 1589 and has identified the errors associated with the 2017 balance in Account 1588. It confirmed with the OEB at its Cost of Service orientation session on July 17, 2019 that it would not be required to retroactively apply the *Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment.* However, it did consider the accounting guidance in the context of historical balances that have yet to be disposed on a final basis. Further the combined balance in Account 1588 for which Burlington Hydro is requesting disposition is $679,979 for 2017 and 2018. As identified above this balance includes a reversal of over-accrued unbilled revenue related to 2016 of $911,135. Therefore the balance in Account 1588 related to 2017 and 2018 activity is $231,156 which is relatively immaterial. The actual 2017 and 2018 balances in Account 1589 are also within 1% of the expected balances as identified in Table 14 below. As such Burlington Hydro is requesting final disposition of its 2017 and 2018 Group 1 balances as detailed below.

The Group 1 balances have been calculated in accordance with the EDDVAR Report and the letter from the Board dated May 23, 2017 re: *Guidance on Disposition of Accounts 1588 and 1589*. The Group 1 balances as of December 31, 2018, in the amount of $(591,801) have been adjusted for certain items to determine the amount for disposition of ($371,075) as identified in Table 7 below. The interest rates used to record carrying charges are 1.50% per year for Q1 2018; 1.89% per year for Q2 2018 – Q3 2018; 2.17% per year for Q4 2018; 2.45% per year for Q1 2019; 2.18% per year for Q2 2019 – Q4 2019. The interest rate used for January – April 2020 is 2.18% per year. These interest rates are consistent with the Board’s prescribed interest rates.

Table 7 – Group 1 Account Balances for Disposition

Description	Amount
Group 1 Balances as at December 31, 2018	**($591,801)**
Subtract 2018 IRM Filing Disposition	$0
Subtract 1595 Unaudited Balances not Requested for Disposition	$264,461
Add 2019 Projected Carrying Charges	($33,113)
Add 2020 Projected Carrying Charges	($10,622)
Adjusted Group 1 Balances for Disposition - Repayment to Customers	**($371,075)**

Burlington Hydro has calculated the disposition threshold, based on the adjusted Group 1 balances to be $0.0002/kWh, as identified in Table 8 below, which does not meet the threshold of $0.001/kWh. Nonetheless, Burlington Hydro is electing to dispose of its Group 1 balances in this Application for the following reasons:

- The balances represent two years of activity – 2017 and 2018;
- Rate riders are generated for all classes for both the DVA and GA rate riders, with the exception of a GA rate rider for the Unmetered Scattered Load class, for which there are no non-RPP customers;
- The balance is a refund to customers;
- If Burlington Hydro were to dispose of these balances in its 2021 rate application for rates effective May 2021, the disposition would be on average 3½ years after the variance occurred (2017 and 2018 balances disposed of in 2021 and 2022) which does not send a timely price signal to customers; and
- It becomes administratively difficult to track three years of DVA balances for disposition particularly for customers transitioning between Class A and Class B.

Table 8 – Calculation of Disposition Threshold

Variance Account	USoA	Amount
Low Voltage	1550	$0
Smart Metering Entity Charge	1551	($67,894)
RSVA - Wholesale Market Service Charge	1580	($1,894,320)
RSVA - Wholesale Market Service Charge - Capacity Based Recovery - Class B	1580	($119,584)
RSVA - Retail Transmission Network Charge	1584	$128,539
RSVA - Retail Transmission Connection Charge	1586	$406,939
RSVA - Power	1588	$679,797
RSVA - Global Adjustment	1589	$870,555
Disposition and Recovery of Regulatory Balances	1595	($375,107)
Adjusted Group 1 Balances for Disposition		**($371,075)**
2018 kWh		1,597,636,816
Threshold Test $/kWh		**($0.0002)**

Burlington Hydro confirms that no adjustments have been made to any deferral and variance account balances previously approved by the OEB on a final basis. Burlington Hydro also confirms that the last Board approved balance of ($2,157,476) has been transferred to Account 1595 (as identified in Burlington Hydro's IRM application EB-2017-0029).

Burlington Hydro has completed and filed Tabs 3 to 7 of the IRM Model. Table 9 below provides a summary of the Continuity Schedule in Tab 3. The disposition of the LRAMVA balance is discussed in further detail on page 35.

Table 9 – Group 1 and LRAMVA Continuity Schedule

Variance Account	USoA	Principal as at Dec 31, 2018 (as per RRRs)	Carrying Charges to Dec 31, 2018 (as per RRRs)	Principal Disposition (EB-2018-0021)	Carrying Charges Disposition (EB-2018-0021)	Principal Adjustment 2017/2018	Interest Adjustment 2017/2018	Carrying Charges to April 30, 2020	2020 Disposition
Low Voltage	1550	$0	$0	$0	$0	$0	$0	$0	$0
Smart Metering Entity	1551	($66,730)	$816	$0	$0	$0	$0	($1,980)	($67,894)
RSVA - Wholesale Market Service Charge	1580	($1,778,085)	($63,474)	$0	$0	$0	$0	($52,761)	($1,894,320)
RSVA - Wholesale Market Service Charge - CBR B	1580	($117,084)	$974	$0	$0	$0	$0	($3,474)	($119,584)
RSVA - Retail Transmission Network Charge	1584	$122,764	$2,133	$0	$0	$0	$0	$3,643	$128,539
RSVA - Retail Transmission Connection Charge	1586	$390,521	$4,830	$0	$0	$0	$0	$11,588	$406,939
RSVA - Power	1588	$2,775,136	$60,788	$0	$0	($2,173,966)	$0	$17,838	$679,797
Sub-total excluding RSVA - Global Adjustment		**$1,326,522**	**$6,066**	**$0**	**$0**	**($2,173,966)**	**$0**	**($25,146)**	**($866,524)**
RSVA - Global Adjustment	1589	$777,450	$70,036	$0	$0	$0	$0	$23,069	$870,555
Sub-total including RSVA - Global Adjustment		**$2,103,972**	**$76,102**	**$0**	**$0**	**($2,173,966)**	**$0**	**($2,077)**	**$4,031**
Disposition and Recovery of Regulatory Balances (2016)	1595	($686,803)	$695,703	$0	$0	$0	$0	($20,379)	($11,480)
Disposition and Recovery of Regulatory Balances (2017)	1595	($283,259)	($71,964)	$0	$0	$0	$0	($8,405)	($363,627)
Total Group 1 Balances for Disposition		**$1,133,910**	**$699,842**	**$0**	**$0**	**($2,173,966)**	**$0**	**($30,861)**	**($371,075)**
LRAMVA Variance Account	1568	$1,485,333	$34,617	($358,113)	($15,363)	$0	$0	$33,525	$1,180,000
Total Balances for Disposition		**$2,619,244**	**$734,459**	**($358,113)**	**($15,363)**	**($2,173,966)**	**$0**	**$2,664**	**$808,925**
Disposition and Recovery of Regulatory Balances (2018)	1595	($791,962)	$166,899	$0	$0	$0	$0		
Disposition and Recovery of Regulatory Balances (2019)	1595	$0	$0	$358,113	$15,363	$0	$0		
Total Balances per Tab 3. Continuity		**$1,827,282**	**$901,358**	**$0**	**$0**	**($2,173,966)**	**$0**	**$2,664**	

Table 10 summarizes the allocation of Group 1 balances to rate class. Burlington Hydro proposes to dispose of the Group 1 Account balance of $(371,075), payable to ratepayers, as follows: $(448,734) via rate riders effective May 1, 2019 to April 30, 2020; and $77,659 through billing adjustments to transition customers as described in the Global Adjustment and Capacity Based Recovery sections below.

Table 11 provides the calculation of the Group 1 rate riders by rate class. Burlington Hydro is seeking a one-year disposition period for the Group 1 balances. This approach is consistent with the EDDVAR Report which states on page 6 that “the default disposition period used to clear the account balances through a rate rider should be one year”.

Table 10 – Allocation of Group 1 Balances to Rate Class

Variance Account	USoA	Residential	GS<50 kW	GS>50 kW	USL	Streetlighting	Total
Low Voltage	1550	$0	$0	$0	$0	$0	$0
Smart Metering Entity Charge	1551	($62,111)	($5,783)	$0	$0	$0	($67,894)
RSVA - Wholesale Market Service Charge	1580	($634,671)	($205,306)	($1,041,846)	($3,722)	($8,775)	($1,894,320)
RSVA - Wholesale Market Service Charge - CBR B	1580	($44,704)	($14,461)	($54,518)	($262)	($618)	($114,563)
RSVA - Retail Transmission Network Charge	1584	$43,066	$13,931	$70,694	$253	$595	$128,539
RSVA - Retail Transmission Connection Charge	1586	$136,341	$44,104	$223,810	$799	$1,885	$406,939
RSVA - Power	1588	$227,758	$73,676	$373,878	$1,336	$3,149	$679,797
Disposition and Recovery of Regulatory Balances (2016)	1595	($3,765)	($1,217)	($6,406)	($23)	($69)	($11,480)
Disposition and Recovery of Regulatory Balances (2017)	1595	($119,270)	($38,181)	($203,268)	($727)	($2,182)	($363,627)
Sub-total excluding RSVA - Global Adjustment		**($457,357)**	**($133,236)**	**($637,655)**	**($2,346)**	**($6,014)**	**($1,236,609)**
RSVA - Global Adjustment	1589	$11,882	$39,281	$726,418	$0	$10,295	$787,875
Total Group 1 Balances for Disposition via Rate Rider effective May 1, 2019		**($445,475)**	**($93,955)**	**$88,763**	**($2,346)**	**$4,281**	**($448,734)**
Add: CBR Balance to be Recovered via Bill Adjustment	1580						($5,020)
Add: GA Balance to be Recovered via Bill Adjustment	1589						$82,679
Total Group 1 Balances for Disposition							**($371,075)**

1 **Table 11 – Calculation of Group 1 Rate Riders by Rate Class**

Rate Class	DVA Rate Rider			
	Unit	Consumption/ Demand	$ Variance Account	$ per unit
RESIDENTIAL	kWh	535,270,676	($412,653)	($0.0008)
GENERAL SERVICE LESS THAN 50 kW	kWh	173,151,275	($118,775)	($0.0007)
GENERAL SERVICE 50 TO 4,999 kW	kW	2,378,408	($583,137)	($0.2452)
UNMETERED SCATTERED LOAD	kWh	3,138,760	($2,084)	($0.0007)
STREET LIGHTING	kW	20,571	($5,396)	($0.2623)
TOTAL			**($1,122,046)**	

Rate Class	CBR Rate Rider			
	Unit	Consumption/ Demand	$ Variance Account	$ per unit
RESIDENTIAL	kWh	535,270,676	($44,704)	($0.0001)
GENERAL SERVICE LESS THAN 50 kW	kWh	173,151,275	($14,461)	($0.0001)
GENERAL SERVICE 50 TO 4,999 kW	kW	1,819,941	($54,518)	($0.0300)
UNMETERED SCATTERED LOAD	kWh	3,138,760	($262)	($0.0001)
STREET LIGHTING	kW	20,571	($618)	($0.0300)
TOTAL			**($114,564)**	

Rate Class	GA Rate Rider			
	Unit	non-RPP Consumption	$ Variance Account	$ per unit
RESIDENTIAL	kWh	8,487,586	$11,882	$0.0014
GENERAL SERVICE LESS THAN 50 kW	kWh	28,059,070	$39,281	$0.0014
GENERAL SERVICE 50 TO 4,999 kW	kWh	518,897,816	$726,418	$0.0014
UNMETERED SCATTERED LOAD	kWh	-	$0	n/a
STREET LIGHTING	kWh	7,353,934	$10,295	$0.0014
TOTAL			**$787,875**	

A comparison of the rate riders effective from May 1, 2019 to April 30, 2020 to the proposed rate riders effective from May 1, 2020 to April 30, 2021 is provided in Table 12 below.

Table 12 – Comparison of Current Approved to Proposed Rate Riders

Rate Class	DVA Rate Rider			CBR Rate Rider			GA Rate Rider		
	Unit	Effective May 1, 2019	Effective May 1, 2020	Unit	Effective May 1, 2019	Effective May 1, 2020	Unit	Effective May 1, 2019	Effective May 1, 2020
RESIDENTIAL	kWh	$0.0000	($0.0008)	kWh	$0.0000	($0.0001)	kWh	$0.0000	$0.0014
GENERAL SERVICE LESS THAN 50 kW	kWh	$0.0000	($0.0007)	kWh	$0.0000	($0.0001)	kWh	$0.0000	$0.0014
GENERAL SERVICE 50 TO 4,999 kW	kW	$0.0000	($0.2452)	kW	$0.0000	($0.0300)	kWh	$0.0000	$0.0014
UNMETERED SCATTERED LOAD	kWh	$0.0000	($0.0007)	kWh	$0.0000	($0.0001)	kWh		
STREET LIGHTING	kW	$0.0000	($0.2623)	kW	$0.0000	($0.0300)	kWh	$0.0000	$0.0014

Wholesale Market Participants

A Wholesale Market Participant ("WMP") refers to any entity that participates directly in any of the Independent Electricity System Operator ("IESO") administered markets; and therefore should not be allocated balances related to transmission network and connection charges and disposition/refund of regulatory balances. Burlington Hydro confirms that none of its customers are WMPs.

Global Adjustment

Class B and A Customers

Burlington Hydro settles GA costs with Class A customers on the basis of actual GA prices and therefore has not allocated any of the GA variance balance to these customers for the period that they were designated Class A.

For non-RPP Class B customers, the $RSVA_{GA}$ captures the difference between the amounts billed (or estimated to be billed) by the distributor and the actual amount paid by the distributor to the IESO for those customers. The manner in which the balance in the $RSVA_{GA}$ is disposed of is dependent on whether a customer was a non-RPP Class B customer for the full year the $RSVA_{GA}$ balance relates to or whether they transitioned between Class A and Class B during that year.

The customers who transitioned between Class A and Class B in 2017 and 2018 are identified in Table 13 below.

Table 13 – Class A/B Customer Transition

Description	2017	2018
Class A to Class B	0	5
Class B to Class A	24	4
Class A since ICI inception	2	2
Total Class A at July 1	**26**	**25**

These transition customers are responsible for the GA variance balance which accrued during the period for which they were non-RPP Class B customers. Burlington Hydro completed tabs "6. Class A Consumption Data", "6.1a GA Allocation" and "6.1 GA" in the IRM Model to allocate the applicable portion of $RSVA_{GA}$ to these customers, based on customer specific consumption levels. This amount represents $82,679 of the total $RSVA_{GA}$ balance which will be recovered from these transition customers in 12 equal monthly payments. The remaining balance of $787,875 will be recovered from customers who were non-RPP Class B customers for all of 2017 and 2018 through a separate rate rider. Rate riders for the GA are calculated on a consumption basis (kWhs).

GA Analysis Workform

The GA Analysis Workform ("GA Workform") for 2017 and 2018 is provided as Appendix D and is filed as a live excel file: Attachment 2_GA Analysis Workform_BHI_20191010.

Burlington Hydro provides "Appendix A" of the GA Analysis Workform Instructions ("GA Methodology Description") as Appendix E. Burlington Hydro notes that this Appendix has been completed based on its accounting procedures in place prior to January 1, 2019. Since the implementation of the OEB's *Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment*, effective January 1, 2019 Burlington Hydro's accounting procedures have changed.

The GA Workform compares the principal activity in the general ledger for the $RSVA_{GA}$ to the expected principal balance based on monthly GA volumes, revenue and costs. The GA Workform provides a tool to assess if the principal activity in the $RSVA_{GA}$ in a specific year is reasonable.

The principal activity in the $RSVA_{GA}$ recorded in 2017 was $914,852 excluding dispositions, as identified in Table 14 below. The principal activity, adjusted for known adjustments of $795,386 was $1,710,238. This is compared to the expected principal balance in the $RSVA_{GA}$ of $1,105,942 calculated in Appendix D, which results in an unreconciled difference of $604,296. This represents 0.87% of Burlington Hydro's 2017 IESO purchases which is within the OEB's threshold (+/- 1% of IESO purchases).

The principal activity in the $RSVA_{GA}$ recorded in 2018 was ($818,805) excluding dispositions, as identified in Table 14 below. The principal activity, adjusted for known adjustments of ($88,582) was ($907,387). This is compared to the expected principal balance in the $RSVA_{GA}$ of ($1,089,002) calculated in Appendix D, which results in an unreconciled difference of $181,616. This represents 0.33% of Burlington Hydro's 2018 IESO purchases which is within the OEB's threshold (+/- 1% of IESO purchases).

Table 14 – GA Workform Summary

Description	2017	2018
Principal Activity in $RSVA_{GA}$ excluding dispositions	**$914,852**	**($818,805)**
Add Known Adjustments	$795,386	($88,582)
Adjusted Principal Activity in $RSVA_{GA}$	**$1,710,238**	**($907,387)**
Expected Principal Activity in $RSVA_{GA}$	$1,105,942	($1,089,002)
Variance $	**$604,296**	**$181,616**
Total IESO Purchases	$69,455,496	$54,327,011
Absolute Variance as a % of IESO Purchases	**0.87%**	**0.33%**

Description of Settlement Process

A distributor is required to support its GA claims with a description of its settlement processes with the IESO in accordance with page 14 of the Chapter 3 Filing Requirements. Burlington

Hydro's settlement process with the IESO is dependent on the type of consumer as identified in Table 15 below.

Table 15 – IESO Settlement Process by Customer

Consumer	Revenue (collected from customer by BHI)	Expense (paid to IESO by BHI)	Settlement Process	Impact to $RSVA_{GA}$
Class A	billed actual GA	pay actual GA	Burlington Hydro pays the IESO Actual GA and bills customers Actual GA - no further settlement with the IESO is required	none
Class B non-RPP	billed 1st estimate GA	pay actual GA	Burlington Hydro pays the IESO Actual GA and bills all customers 1st estimate GA - no further settlement with the IESO is required	difference between revenues and costs recorded to GA variance account on a monthly basis and recovered from/repaid to Class B non-RPP consumers on disposal of the $RSVA_{GA}$
Class B RPP	billed RPP TOU or Tiered Rates	pay actual GA	Burlington Hydro pays the IESO Actual GA and bills customers RPP rates - Burlington Hydro settles with the IESO on a monthly basis via the RPP vs. Market Price Claim discussed in further detail below	none - GA is not billed separately for Class B RPP consumers; incorporated into RPP rates; any variances are recorded in $RSVA_{POWER}$

Class A Consumers

Burlington Hydro bills Class A consumers GA based on their percentage contribution to the top five Ontario peak demand hours. Class A consumers are billed their proportion of actual GA as published by the IESO. Burlington Hydro settles GA costs with Class A consumers on the basis of actual costs and as such, none of the variance in the GA account balance is attributed to these customers.

Class B non-RPP Consumers

Burlington Hydro uses the IESO's 1^{st} estimate for GA to invoice non-RPP Class B consumers and record unbilled revenue entries for these customers. Burlington Hydro confirms that the same GA rate (1^{st} estimate) is used for all non-RPP Class B consumers in all applicable rate classes for all billing and unbilled revenue transactions.

Class B RPP Consumers

Class B RPP consumers are billed by Burlington Hydro throughout the month at RPP Time of Use ("TOU") or Tiered Rates. The difference between how much Burlington Hydro recovers from RPP consumers at these rates and the amount Burlington Hydro pays to the IESO for the commodity and GA, is managed through the RPP vs. Market Price claim. In order to determine the amount of the RPP vs. Market Price claim - paid to or recovered from the IESO on a monthly basis - Burlington Hydro must determine the monthly consumption attributable to RPP customers and allocate this consumption into TOU periods and Tiered blocks. There are two components to Burlington Hydro's RPP vs. Market Price claim:

1. Estimate claim for the current month (based on estimated consumption and estimated energy prices)
2. True-up of prior month claim (based on actual consumption where available and actual energy prices)

The data used for each of the components of the RPP vs. Market Price claim is identified in Table 16 below. This table also includes the source of the data and the date it becomes available. The total kWh consumption for all of Burlington Hydro's customers is equal to the sum of the kWh wholesale power purchased from the IESO plus embedded generation. Total non-RPP kWh consumption is deducted from this total kWh consumption to determine the kWh consumption attributable to RPP customers. As such, volumes related to embedded generation are included in the calculation.

In order to determine the dollar amount of the RPP vs. Market Price Claim, the RPP kWh consumption must be allocated into TOU periods (on-peak, mid-peak and off-peak) and Tiered blocks (Tier 1 and Tier 2). Burlington Hydro uses its Customer Information System, Daffron, to determine this allocation. This allocation is based on billed data i.e. customers' meter read date range.

Table 16 – Data Used for RPP vs. Market Price Claim

Description		Estimated Claim - Current Month		True-up of Prior Month Claim	
Activity Month Example		**April 2018**		**April 2018**	
Submission Date Example		**Day 4 (4-May)**		**Day 4 (6-Jun)**	
		Estimate/Actual	**Data Available**	**Estimate/Actual**	**Data Available**
Total kWh Wholesale Power Purchased from the IESO	a	estimate (Utilismart)	1st day of following month (e.g. Day 1 May for April data)	actual (IESO)	Business Day 10 of following month (e.g. Day 10 May for April data)
Add: kWh Embedded Generation	b	estimate (Utilismart)		Prior month actual (Utilismart)	Business Day 10 of current month
Less: kWh Consumption for Class A and non-RPP Interval Metered Customers billed at Spot	c	estimate (Daffron)		actual (Daffron)	Business Day 13 of following month (e.g. Day 13 May for April data)
Less: kWh Consumption for non-RPP non-Interval Metered and Retailer Customers billed at Spot [1]	d	estimate (Daffron)		estimate (Daffron)	1st day of following month (e.g. Day 1 May for April data)
Total kWh RPP Class B customers	e	e = a+b-c-d		e = a+b-c-d	
Rates used for Electricity Cost		estimate COP (Utilismart)	1st day following month (e.g. Day 1 May for April data)	actual COP (IESO)	Business Day 10 of following month (e.g. Day 10 May for April data)
		2nd estimate GA (IESO)	last day current month	actual GA (IESO)	

1. Burlington Hydro's billing system. Daffron, does not record consumption on a calendar month basis for these customers

1. *Estimated Claim for the current month (based on estimated consumption and energy prices)*

Actual monthly consumption attributable to RPP customers is not available at the time the current month RPP vs. Market Price Claim is submitted to the IESO. Consequently, Burlington Hydro calculates monthly consumption attributable to RPP customers in accordance with the "Estimated Claim – Current Month" column in Table 16 above. All data are estimates available from Daffron or Utilismart, who is responsible for Burlington Hydro's wholesale meter data collection and analysis. As mentioned above, to determine revenue, RPP kWh are allocated to TOU periods and Tiered blocks using billing data from Daffron. Cost is determined using estimates for COP (available on the first day of the following month) and GA (2nd estimate available on the last day of the current month).

2. *True-up of prior month claim using (based on actual consumption where available and actual energy prices)*

In the month after the RPP vs. Market Price claim is submitted, more accurate information is available to determine the claim. The prior month's claim is recalculated using updated values for purchases and energy prices. The difference between the current month's claim and the re-estimated claim is submitted in the subsequent month (e.g. re-estimated claim for April is submitted as part of the May RPP vs. Market Price Claim on Day 4 of June). All consumption data is based on actual consumption, with the exception of kWh consumption for non-RPP non-Interval Metered and Retailer Customers. Burlington Hydro uses billed data as a proxy for consumption for these customers. Daffron does not store consumption by calendar month for customers billed on a non-calendar month basis. RPP kWh are allocated to TOU periods and Tiered blocks using billing data from Daffron, similar to the current month claim described above. Cost is determined using actual COP and GA (both available on Business Day 10 of the following month).

Internal Control Tests

Burlington Hydro performs several internal control tests to validate estimated and actual consumption figures used in its RPP settlement process and subsequent true-up adjustments as follows:

- Comparison of IESO wholesale kWh purchased to Utilismart data
- Reconcile 1598 Claim on receipt of invoice
- Monthly independent validation of kWh used for settlement by type of consumer
- Verification of kWh inputs for settlement vs. Daffron reports
- Complete analysis of $RSVA_{POWER}$ and $RSVA_{GA}$ on a monthly basis
- Complete GA Analysis Workform on a quarterly basis to identify any data outliers and material variances

In addition, as identified previously, Burlington Hydro undertook a full review of Accounts 1588 and 1589 and will be implementing the OEB's Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment effective January 1, 2019.

Description of Accounting Methods and Transactions for 2017

Power purchases, GA purchases and the RPP vs. Market Price Claim included in one or both of the Cost of Power (Account 4705) and GA (Account 4707) year-end balances are updated in the current period for:

- the actual spot price of power and GA on the IESO invoices (charge types 101 and 148 respectively); and
- actual purchased volumes on IESO invoices.

All revenues and costs (Power, GA and the RPP vs. Market Price Claim) for RPP customers are recorded in Cost of Power (Account 4705). The difference between Cost of Power revenues and expenses are recorded in $RSVA_{POWER}$ and the difference between GA revenues and expenses are recorded in $RSVA_{GA}$.

Burlington Hydro estimates the RPP vs. Market Price Claim for submission to the IESO on Day 4 of the following month. It then revises the claim with the IESO in the subsequent month (submits the difference) using the methodology described above. Both the original estimate and the true-up of the original estimate are recorded in the month to which the consumption relates. As a result, there are no subsequent adjustments recorded after the reporting period that adjust the initial transactions from preliminary estimates to actual figures based on consumption data.
In accordance with page 15 of the Chapter 3 Filing Requirements, Burlington Hydro has completed the GA Analysis Workform for 2017 and 2018, the fiscal years subsequent to the most recent year (2016) in which $RSVA_{POWER}$ and $RSVA_{GA}$ were approved for disposition on a final basis by the OEB.

Burlington Hydro confirms that it does not use the actual GA price to bill non-RPP Class B consumers. It uses the 1st estimate GA as previously identified. Therefore non-RPP Class B consumers are included in the allocation of the balance of $RSVA_{GA}$ and the calculation of the resulting rate riders.

Commodity Accounts 1588 and 1589

RPP Settlement True-ups

Effective May 23, 2017, per the OEB's letter titled *Guidance on Disposition of Accounts 1588 and 1589*, applicants must record RPP Settlement true-up claims pertaining to the period that is being requested for disposition in the $RSVA_{POWER}$ and the $RSVA_{GA}$. Burlington Hydro confirms it has followed the guidance in the above mentioned letter; specifically:

- RPP settlement true-up claims are conducted on a monthly basis;
- The balances in $RSVA_{POWER}$ and $RSVA_{GA}$ that are requested for disposition in this Application reflect the RPP settlement amounts pertaining to the period that is being requested for disposition i.e. 2017 and 2018.
- Burlington Hydro has no true-up claims for 2017 and 2018 which have not already been reflected in the 2017 and 2018 audited financial statements.

Certification of Evidence

Burlington Hydro provides CFO certification that it has robust processes and internal controls in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed of in Appendix C.

Status Update on Implementation of "*Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment*"

Burlington Hydro confirms that it has implemented the "*Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment*" issued by the OEB on February 21, 2019. It implemented this guidance effective January 1, 2019, by August 31, 2019. It has reviewed its historical balances and has made corrections as identified above. Burlington Hydro identifies the following exceptions to the implementation of the guidance:

- Burlington Hydro does not record different rates for RPP and non-RPP cost of power

- Burlington Hydro does not re-estimate unbilled revenue at the end of each month; it does so at the end of the fiscal year. This approach has no impact to the RPP vs. Market Price Claim with the IESO (revenue for the purposes of calculating the RPP vs. Market Price Claim is based on the best estimate of actuals at the 2nd true-up); nor does it have an impact to the balances in the DVA accounts since these are disposed at the end of the fiscal year. Burlington Hydro updated unbilled revenue at year end.

Burlington Hydro is in the middle of a Customer Information System conversion, with an implementation date scheduled for mid-2020. It is unable to, and inefficient to, develop a program to address the two items identified above in a legacy system which will be obsolete in 2020. Burlington Hydro plans to pursue implementing these changes in its new CIS.

Capacity Based Recovery ("CBR")

Burlington Hydro confirms that it has followed the OEB's accounting guidance on the disposition of CBR variances. Burlington Hydro confirms that it had Class A customers during 2017 and 2018, the period for which the Account 1580 CBR Class B Sub-account balance requested for disposition accumulated.

Burlington Hydro completed tab "6.2a CBR B_Allocation" in the IRM Model to allocate the applicable portion of Account 1580 CBR Class B Sub-account balance to customers who transitioned between Class A and Class B during 2017 and 2018. This amount represented ($5,020) of the total balance of ($119,584). A separate rate rider to dispose of the remaining balance of ($114,564) was calculated in Tab "6.2 CBR B" of the IRM Model which is applied to Class B customers only. Burlington Hydro excluded the consumption and demand for transition customers and Class A customers that were Class A for the entire period that the CBR Class B balance accumulated. These rate riders are identified in Table 12 above.

Application of Recoveries in Account 1595

Burlington Hydro is seeking disposition of the audited account balances in the Account 1595 sub-account related to the disposition of 2016 and 2017 regulatory balances. The total claim for which Burlington Hydro is seeking disposition is $(375,407) as identified in Table 8 of which

$27,174 and ($350,961) are residual balances for 2016 and 2017 respectively, as identified in Table 17 below.

1595 Analysis Workform

The 1595 Analysis Workform is provided as Appendix F and is filed as a live excel file: Attachment 3_1595 Analysis Workform_BHI_20191010. The Workform compares principal and interest amounts previously approved for disposition to the residual balances remaining after amounts have been recovered/refunded to customers through rate riders. Balances in Account 1595 are assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 Accounts. A residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition is considered material. Burlington Hydro confirms that it has not disposed of the residual balances in Account 1595 for the 2016 and 2017 vintage years.

Table 17 below compares the residual balances in these two groups of accounts to the total balances approved for disposition.

2016 Balances: The total Group 1 and Group 2 balances excluding Account 1589; and the balance in Account 1589 – Global Adjustment generate a variance of 0.1% and 1.8% respectively for a total variance of 0.9%. This represents an immaterial residual balance and Burlington Hydro proposes that this account balance be approved for disposition.

2017 Balances: The total Group 1 and Group 2 balances excluding Account 1589; and the balance in Account 1589 – Global Adjustment generate a variance of 14.2% and 12.3% respectively for a total variance of ($355,222) or 16.3%. Burlington Hydro provides an explanation of the variance below.

Table 17 – Account 1595 Residual Balances

Description	2016 Balances		
	Total Original Balances Approved for Disposition	Residual Balances	Collections/ Returns Variance
Total Group 1 and Group 2 Balances excl Account 1589	$1,698,354	$2,185	0.1%
Account 1589 - Global Adjustment	$1,407,028	$24,989	1.8%
Total Group 1 and Group 2 Balances	**$3,105,382**	**$27,174**	**0.9%**

Description	2017 Balances		
	Total Original Balances Approved for Disposition	Residual Balances	Collections/ Returns Variance
Total Group 1 and Group 2 Balances excl Account 1589	($4,676,024)	($636,749)	13.6%
Account 1589 - Global Adjustment	$2,494,014	$285,788	11.5%
Total Group 1 and Group 2 Balances	**($2,182,010)**	**($350,961)**	**16.1%**

Burlington Hydro has a residual balance of ($350,961) in its Account 1595 for 2017 dispositions. The expected balance as calculated in the 1595 Workform and identified in Table 18 below is $137,018. This results in an unreconciled difference of ($487,979). Burlington Hydro provides an explanation of this difference as follows and in Table 18 below:

Table 18 – Explanation of 2017 Account 1595 Residual Balances

Description	Amount
Total Balances Approved for Disposition	($2,182,011)
Total Refunds/Recoveries in Account 1595	$1,831,050
Residual Balance in Account 1595 Due From/(Due to) Customers	**($350,961)**
Under/(Over) Collection due to Calculated Rate Rider vs. Approved Balances	$137,018
Unreconciled Difference in Account 1595	**($487,979)**
CBR Rider Double Counted in OEB's IRM Model [1]	($452,213)
Prior Year 1595 Residual Balances not Cleared [2]	($65,550)
Tax Sharing Rate Rider not generated/not recovered from customers [3]	$29,785
Total Difference	**($487,979)**

1. CBR Rider included in DVA rider and as a separate rate rider in the OEB's IRM model in error
2. 2014 LRAMVA and 2013 Z-factor residual balances; and unbilled revenue adjustment not posted to prior year Account 1595
3. 2017 Tax Sharing amount recorded to Account 1595 as approved in EB-2016-0029 but not disposed of because rate riders were not significant

The unreconciled difference of ($487,979) in Account 1595 (2017) is as follows:

1. The OEB's IRM Model used in Burlington Hydro's 2017 IRM application (EB-2016-0059) calculated a DVA rate rider based on a Group 1 Account balance of ($5,220,572) and a CBR rider based on a CBR balance of $465,509. However the Group 1 Account balance of ($5,220,572) in the IRM Model already included the CBR balance of $465,509. As a result the DVA rate rider was understated by $465,509 and customers were overcharged by the rate rider equivalent of this amount. This over-collection from customers represents **($452,231)** of the ($487,979) unreconciled difference.

2. Burlington Hydro identified **($65,550)** which should have been recorded to prior year dispositions in Account 1595. This amount relates to 2014 LRAMVA and 2013 Z-factor; and unbilled revenue amounts accrued but not reversed. Since this amount is a refund to customers, Burlington Hydro respectfully requests that this amount be included in Account 1595 (2017) for disposition.

3. Burlington Hydro received approval to dispose of a shared tax change amount of $29,785 in its 2017 IRM application (EB-2016-0059). Burlington Hydro requested and received OEB approval that this amount be recorded in Account 1595 for disposition in a future application given the associated rate riders would be negligible.[3] This amount has not been collected from rate payers yet and represents **$29,785** of the ($487,979) unreconciled difference.

[3] p6 Decision and Rate Order EB-2016-0059, April 20, 2017

Lost Revenue Adjustment Mechanism Variance Account

The Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to Conservation and Demand Management ("CDM") activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.

At a minimum, distributors must apply for the clearance of its energy and/or demand related LRAMVA balances attributable to energy efficiency programs in a CoS application. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

Burlington Hydro is applying for disposition of the balance in its 2018 LRAMVA account resulting from its Conservation and Demand Management ("CDM") activities in 2013 – 2018. The total amount requested for disposition, identified in Table 19 below, is a debit of $1,180,000 including carrying charges of $52,781 through to April 30, 2020.

Table 19 – LRAMVA Balance

Year	Principal	Interest	Total
2017	$581,971	$31,567	$613,538
2018	$545,248	$21,214	$566,462
Total	**$1,127,219**	**$52,781**	**$1,180,000**

Burlington Hydro considers the amount of $1,180,000 significant as it is above its materiality threshold of $144,178, defined by the OEB as 0.5% of distribution revenue requirement. Burlington Hydro's actual savings from CDM activities for 2017 and 2018 were above the estimated projections used in the load forecast in its last Cost of Service Application EB-2013-0115, resulting in an under-collection of distribution revenue from customers during this period. Burlington Hydro's most recent application for the recovery of lost revenues due to CDM activities was filed in its 2018 IRM application (EB-2018-0021). In that proceeding, the Board approved Burlington Hydro's request to recover lost revenues in 2013 to 2016.

There is a difference of ($92,657) in the LRAMVA Variance account as compared to the RRRs as identified in Table 20 below and on Tab “3. Continuity Schedule” of the IRM Model.

Table 20 – Explanation of Difference between LRAMVA and RRR balance

Description	Amount
2018 RRR Balance	$1,427,294
2018 Balance per Tab 3. Continuity Schedule	$1,519,951
Variance	**($92,657)**
2016 - difference between RRRs and final LRAMVA balance approved by Board in EB-2018-0021	($7,336)
2017 - difference between estimate and final LRAMVA balance based on final IESO reports	($39,234)
2018 - difference between estimate and final LRAMVA balance based on final IESO reports	($46,087)
Total Difference	**($92,657)**

The difference of $(92,657) is due to the following:

1. The final approved LRAMVA balance of $373,476 differed from that filed in Burlington Hydro’s RRRs by **$(7,336)**. Burlington Hydro did not update its RRR filing as the amount was not material and it planned to incorporate this adjustment when it updated its LRAMVA balances later in 2019 to reflect final IESO results for 2017 and 2018.

2. The lost revenue associated with 2017 and 2018 programs filed in Burlington Hydro’s 2018 RRR filing was an estimate. The difference between this estimate and the final LRAMVA balance based on final IESO reports for 2017 and 2018 is **($39,234)** and **($46,087)** respectively.

Burlington Hydro will file a revision to its 2018 LRAMVA balance in October 2019 for ($92,657). This revision is in compliance with the OEB’s requirement (as per APH FAQs July 2012 Q5) to update LRAM variance account balances based on results of the reported information in the annual evaluation for all CDM programs. Although distributors are normally required to update LRAMVA balances by September 30, Burlington Hydro did not finalize its 2018 LRAMVA balance until October due to the change in methodology required for 2018 programs as a result of the cancellation of the Conservation First Framework.

Burlington Hydro has determined lost revenue in accordance with the Board's 2012 CDM Guidelines, 2015 CDM Guidelines, its 2016 Updated Policy for the calculation of LRAMVA, and the Addendum to Filing Requirements. A description of the calculation of Burlington Hydro's lost revenue is provided in Appendix G – BHI 2017_18 LRAMVA report 20191009 produced by IndEco. Burlington Hydro has completed the 2020 LRAMVA Work form Version 4.0 provided by the OEB to calculate the variance between actual CDM savings and forecast CDM savings. The LRAMVA Workform is filed as a live excel and pdf file: Attachment 4_LRAMVA Workform_BHI_20191010. In accordance with the Chapter 3 Filing Requirements and the Addendum to Filing Requirements, Burlington Hydro confirms that it is seeking recovery of lost revenues for the period January 1, 2017 to December 31, 2018 resulting from the following:

a. Incremental savings from CDM programs implemented in 2017
b. Incremental savings from CDM programs implemented in 2018
c. Prior year savings persistence related to 2013 to 2017 programs

The lost revenue amounts by rate class were determined by multiplying the CDM verified savings, incremental to the LRAMVA threshold, by the Board approved variable distribution rates for 2017 and 2018 as identified in Table 21 below and Tab "3. Distribution Rates" of the LRAMVA Workform.

Table 21 – Distribution Volumetric Rates

Year	Residential (kWh)	GS<50 kW (kWh)	GS>50 kW (kW)	Unmetered Scattered Load (kWh)	Streetlighting (kW)
2017	$0.0098	$0.0138	$2.9785	$0.0161	$4.4858
2018	$0.0056	$0.0140	$3.0151	$0.0163	$4.5410

The LRAMVA claim is based on the most recent and appropriate final CDM evaluation reports from the IESO except 2018 adjustments. The most recent IESO Participation and Cost report was used to determine savings for 2018 and 2017 adjustments. . These reports are filed as live excel files:

- Attachment 5_2017 Final Verified Annual LDC CDM Program Results_Burlington Hydro Inc_Report_20180629;
- Attachment 6_2017 Final Verified Annual LDC CDM Program Results_Burlington Hydro Inc. Project List_20180629; and
- Attachment 7_Participation and Cost Report_Burlington Hydro Inc_2019 04.

Burlington Hydro has relied on the most recent input assumptions available at the time of program evaluation.

Table 22 below identifies the principal and carrying charge amounts by rate class of $1,180,000 as calculated in Tab “1. LRAMVA Summary” of the LRAMVA Workform. Burlington Hydro confirms that projected carrying charges related to the disposition are calculated in the LRAMVA Workform in Tab “6. Carrying Charges”.

Table 22 – Lost Revenue Principal and Carrying Charges

Year	Residential (kWh)	GS<50 kW (kWh)	GS>50 kW (kW)	Unmetered Scattered Load (kWh)	Streetlighting (kW)	Total
Principal 2017 Actuals	$355,591	$130,820	$219,814	$0	$2,483	$708,707
Principal 2017 Forecast	($62,372)	($27,568)	($35,545)	($583)	($668)	($126,736)
Principal 2018 Actuals	$200,294	$174,045	$238,876	$0	$32,890	$646,105
Principal 2018 Forecast	($35,641)	($27,967)	($35,982)	($590)	($677)	($100,857)
Net Principal	**$457,872**	**$249,330**	**$387,163**	**($1,173)**	**$34,028**	**$1,127,219**
Carrying Charges 2017/2018	$22,311	$11,284	$17,889	($55)	$1,352	$52,781
Total Disposition Requested	**$480,183**	**$260,614**	**$405,051**	**($1,228)**	**$35,380**	**$1,180,000**

Table 23 below identifies the rate riders which result from the disposition of the LRAMVA balance of $1,180,000 as calculated in Tab “7. Calculation of Def-Var RR” in the IRM Model.

Table 23 – LRAMVA Rate Riders

Year	Residential (kWh)	GS<50 kW (kWh)	GS>50 kW (kW)	Unmetered Scattered Load (kWh)	Streetlighting (kW)
Volumetric Rate Rider	$0.0009	$0.0015	$0.1703	($0.0004)	$1.7199

Burlington Hydro proposes recovery of the LRAMVA balance over a 1 year period.

The forecast CDM savings included in the LRAMVA calculation are identified in Table 24 below. These savings were approved in Burlington Hydro's 2014 Cost of Service Application (EB-2013-0115) and used as the comparator for the disposition of the 2016 LRAMVA balances as approved in Burlington Hydro's 2019 IRM Application (EB-2018-0021).

Table 24 – Forecast CDM Savings

Year	Residential (kWh)	GS<50 kW (kWh)	GS>50 kW (kW)	Unmetered Scattered Load (kWh)	Streetlighting (kW)
2017 and 2018	6,364,469	1,997,655	11,934	36,218	149

Burlington Hydro determined the rate class allocations for actual CDM savings in 2017 and 2018 using the Program Results by Project List report provided by the IESO and filed as Attachment 6. This report provides savings by program by customer. These only partially map onto rate classes. Where customers in a program are from more than one rate class, Burlington Hydro considers project specific information for that program, and the rate classes of the customers undertaking the project. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. The allocation was calculated according to the billing determinant of the relevant rate class. That is, for GS<50 projects, their allocation is the percentage of total kWh for projects in that rate class; for GS>50, their allocation is the percentage of total kW for projects in that rate class.

Burlington Hydro confirms that there is no additional documentation or data provided in support of projects that were not included in its Final CDM Annual Report with the exception of Streetlighting as identified below.

Burlington Hydro has not included peak demand (kW) savings from Demand Response programs in its lost revenue calculation in accordance with Board's 2016 Updated Policy on the calculation of peak demand savings.

Streetlighting Project

Starting in 2017, the City of Burlington undertook a series of projects under the Retrofit Program to retrofit streetlights to a more energy efficient light emitting diode (LED) technology. In 2017, the result was a net reduction of 553 kW. The persistence from this project continues into future years, with net reductions of 3,863 kW yearly. The 2018 the project resulted in a net reduction of 3,380 kW, which persists into future years with net reductions of 4,804 kW each year.

- Burlington Hydro forecast demand savings of 149kW in its load forecast in its 2014 CoS Application.
- The street light upgrades that contributed to these savings represent incremental savings attributable to participation in the IESO program and do not include other savings that may have occurred outside of the IESO program.
- The street lighting upgrade projects were undertaken as part of the Retrofit program, and energy savings were reported within results for that program. Because street lighting is not used during peak periods, the IESO does not normally report peak demand savings from street lighting projects. As the street lighting rate class is billed by kW, the calculated net kWh savings from the Retrofit LED upgrade projects do not impact Burlington Hydro’s revenue. Burlington Hydro confirms that the calculated kWh of savings have been manually removed from the 2017 and 2018 Retrofit program results each year. The actual lost revenue from the street lighting retrofit project has been calculated directly by multiplying the reduction in the demand billed by the appropriate rate.
- Burlington Hydro has received reports from the City of Burlington that validate the number and type of bulbs replaced or retrofitted through the IESO program. The street lighting account is billed based on kilowatts (kW) of demand. The street lighting retrofit project was implemented in stages and kW reductions were applied to the municipality’s street lighting account starting in October 2017. Billed demand, calculated reductions and quantity and types of fixtures changed are reported on Tab 8 of the LRAMVA Workform.

- Since streetlights are unmetered and billed by demand, a load profile was not used to determine the demand reduction. The revenue impact is based on actual billed wattages by bulb type before and after the conversions.
- Burlington Hydro did not receive funding from the IESO for the street lighting projects. The net-to-gross ratio used to calculate the street light savings is 0.88 as identified on Tab 8 of the LRAMVA Workform.
- Burlington Hydro provides a table, in live excel format, as Attachment 8_BHI_Summary Streetlight Upgrade Project_10102019 that shows the monthly breakdown of billed demand over the period of the street light upgrade project including data on number of bulbs, type of bulb replaced or retrofitted and average demand per bulb.

Tax Changes

OEB policy, as described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* ("the Supplemental Report"), prescribes a 50/50 sharing of impacts of legislated tax changes from distributors' tax rates embedded in its OEB approved base rate known at the time of application. These amounts will be refunded to or recovered from customers over a 12-month period.

Burlington Hydro's is seeking Board approval of a Shared Tax Savings ("STS") Adjustment of $29,787 for the difference between the actual corporate income tax rate and that which was estimated at the time of rebasing. Burlington Hydro has completed Tabs 8 and 9 of the IRM Model using the Board approved PILs model data filed in Burlington Hydro's most recent CoS application (EB-2013-0115). In that proceeding, Burlington Hydro claimed the Ontario small business deduction which yielded an average corporate income tax rate of 22.34%. Effective May 1, 2014, only companies with less than $15 million of assets are eligible to claim the small business deduction; as Burlington Hydro's assets exceed $100 million it is not eligible for this deduction. As a result, Burlington Hydro's combined actual corporate income tax rate is 26.50% and its PILs expense is expected to increase by $59,573. This results in a $29,787 STS charge to customers. The IRM Model calculated applicable rate riders using the appropriate customer class data underlying the OEB approved rates. A rate rider to four decimal places must be generated for all applicable customer classes in order to dispose of the amounts. Since one or more customer classes do not generate a rate rider to the fourth decimal place, Burlington Hydro proposes that the entire 50/50 STS Adjustment of $29,787 be transferred to Account 1595 for disposition at a future date. This is consistent with the Chapter 3 Filing Requirements and the treatment of the STS Adjustment in Burlington Hydro's 2019 IRM application (EB-2018-0021).

Incremental Capital Module

Burlington Hydro is seeking Board approval for incremental capital funding in this Application. The Incremental Capital Module ("ICM") is available to electricity distributors filing under the Price Cap IR. Burlington Hydro has capital investment requirements which are incremental to its capital requirements within the context of its financial capacities underpinned by existing rates and satisfies the eligibility criteria of materiality, need and prudence as set out in Section 4.1.5 of the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219) issued on September 18, 2014 ("the ACM report"). These criteria are discussed below. The OEB's Capital Module Applicable to ACM and ICM ("the ICM Module") is provided as Appendix H and filed as a live excel file: Attachment 9_ICM Module_BHI_20191010.

Eligibility Criteria

Materiality

The Board states in the ACM report that "a capital budget will be deemed to be material, and as such reflect eligible projects, if it exceeds the Board-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount (as defined in this ACM Report) and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing".

The Board-defined materiality threshold is represented by the following formula:

$$\boldsymbol{Threshold\ Value}\ (\%) = \mathbf{1} + \left[\left(\frac{\boldsymbol{RB}}{\boldsymbol{d}}\right) \times (\boldsymbol{g} + \boldsymbol{PCI} \times (\mathbf{1} + \boldsymbol{g}))\right] \times \left((\mathbf{1} + \boldsymbol{g}) \times (\mathbf{1} + \boldsymbol{PCI})\right)^{\boldsymbol{n}-\mathbf{1}} + \mathbf{10}\%$$

RB = rate base from the distributor's last cost of service

d = depreciation from the distributor's last cost of service

g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application

PCI = Price Cap Index (IPI - stretch_factor) from the distributor's most recent Price Cap IR application as a placeholder for the initial application filing to be updated when new information becomes available

n = number of years since the last rebasing

Burlington Hydro has calculated its materiality threshold using the Board-approved rate base and depreciation from its 2014 Cost of Service application (EB-2013-0115), an annual adjustment or price cap index ("PCI") of 1.2%, and a growth factor of 0.23%. Burlington Hydro has used the Board's 2019 inflation factor of 1.2%, as populated by the OEB in the ICM Module and issued by the OEB on November 23, 2017 to determine the PCI. Burlington Hydro will make a subsequent update for the PCI and 2020 inflation factor, which is expected to be available prior to the Board rendering its Decision on this Application.

The annual growth factor of 0.23% has been calculated in accordance with the ACM Report and is equal to the increase in distribution revenue from 2014 to 2018. 2014 distribution revenue is based on Burlington Hydro's 2014 Board-approved billing determinants at 2018 approved rates to account for Board approved inflationary adjustments.

Table 25 below summarizes the calculation of the threshold capital expenditure amount using the Board's formula identified in the ACM Report. The threshold value for 2020 is 154.8% which results in a threshold capital expenditure value of $6,981,450.

Table 25 - Threshold Capital Expenditure Calculation

Description	Amount
Inflation Factor	1.20%
Less: Productivity Factor	0.00%
Less: Stretch Factor	-0.30%
Price Cap Index ("PCI")	0.90%
2014 Volumes @ 2018 Rates	$31,487,514
2018 Volumes @ 2018 Rates	$31,770,917
Number of Years	4
Growth Factor	0.23%
Year	2020
# of years since rebasing	6
Price Cap Index ("PCI")	0.90%
Growth Factor	0.23%
Dead Band	10%
Rate Base	$131,828,683
Depreciation	$4,510,060
Threshold Value - 2020	**154.80%**
Threshold Capital Expenditure - 2020	**$6,981,450**

Eligible Capital Amount

Table 26 below identifies the maximum eligible incremental capital amount of $4,783,550 for Burlington Hydro in 2020. This amount is determined by deducting the applicable threshold capital expenditure from the 2020 capital forecast.

Table 26 – Maximum Eligible Incremental Capital

Description	2020
Capital Forecast	$11,765,000
Less: Materiality Threshold	$6,981,450
Maximum Eligible Incremental Capital	**$4,783,550**

Table 27 below identifies the eligible capital projects for which Burlington Hydro is seeking approval. These projects total $1.945MM and as such are significant in relation to Burlington Hydro's overall capital expenditure threshold of $7.0MM. The projects are discussed in detail in the project summaries in Appendices H and I.

Table 27 – Eligible Capital Projects

Project Description	Category	2020
Project 1: Customer Information System (CIS) replacement	General Plant	$1,445,000
Project 2: Geographic Information System (GIS) replacement	General Plant	$500,000
Total		**$1,945,000**

Need

The distributor must satisfy the eligibility criteria of need, comprised of: (i) passing the means test; (ii) amounts to be incurred must be based on discrete projects; and (iii) amounts to be incurred must be outside of the base upon which rates were derived.

Means Test

The distributor must pass the Means Test as defined in the ACM Report. If a distributor's regulated return on equity ("ROE") exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed. Burlington Hydro's 2018 actual ROE was 7.03%, 2.33% lower than the deemed ROE of 9.36%. Therefore, Burlington Hydro meets the Means Test.

Discrete Projects

Each project is distinct and unrelated to a recurring annual capital project. The two projects are general plant projects involving the replacement of Burlington Hydro's Customer Information System and Geographic Information System.

Inclusion in Base Rates

These projects were not included in the capital expenditures approved in Burlington Hydro's Cost of Service application (EB-2013-0115) and as such are not funded through existing rates. The projects included in existing rates are identified in Tables 28-32 below.

Prudence

The amounts for which Burlington Hydro is seeking approval are prudent, meaning that Burlington Hydro's decision to incur the amounts represent the most cost-effective option for rate payers. An analysis of options and assessment of prudency is provided for each capital project is provided in the Project Summaries attached as Appendices H and I.

Historical and Proposed Capital Spending by Project

Burlington Hydro provides a summary of historical and proposed capital expenditures by category in Table 28 below. The increase in capital expenditures in 2018 – 2020 as compared to prior years is primarily driven by non-discretionary system access projects. A breakdown of expenditures by project, by category is provided in Tables 29-32 below. Neither of the eligible capital projects were included in the 2014 OEB approved capital budget (2014 CoS) and therefore are not included in base rates. The projects for which Burlington Hydro is seeking an ICM are identified with an asterix.

Table 28 – Historical and Proposed Capital Expenditures by Category

Category	2014 CoS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget
System Access	$8,244,469	$7,498,551	$5,566,544	$9,127,277	$10,237,872	$9,960,519	$12,675,000	$16,146,500
System Renewal	$1,349,241	$1,339,313	$1,831,672	$1,142,404	$1,756,104	$1,893,569	$980,000	$1,755,000
System Service	$908,540	$1,551,534	$984,398	$399,130	$288,085	$366,257	$1,272,287	$1,430,000
General Plant	$807,000	$1,416,828	$1,523,271	$1,114,361	$1,093,357	$1,630,322	$2,039,000	$3,212,500
Total Gross Capital	**$11,309,250**	**$11,806,227**	**$9,905,885**	**$11,783,172**	**$13,375,417**	**$13,850,667**	**$16,966,287**	**$22,544,000**
Contributed Capital	($3,579,205)	($4,389,250)	($1,927,405)	($4,410,452)	($4,681,623)	($3,151,665)	($6,225,000)	($10,779,000)
Total Net Capital	**$7,730,045**	**$7,416,977**	**$7,978,480**	**$7,372,720**	**$8,693,794**	**$10,699,002**	**$10,741,287**	**$11,765,000**

1 **System Access**

The key drivers for system access projects include customer service requests (new customer connections, modifications to existing customer connections, expansions for customer connections or property development); mandated service obligations such as metering; and other third party requirements (system modifications for property or infrastructure development such as road widening). A summary of historical and proposed capital expenditures for system access projects is set out in Table 29 below.

2 **Table 29 – Historical and Proposed Capital Expenditures – System Access**

System Access Projects	2014 CoS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget
Tremaine TS CCRA True-up	$0	$0	$0	$0	$0	$0	$568,000	$0
Tremaine TS Breakers	$0	$0	$0	$0	$0	$1,000,000	$1,000,000	$0
Bronte TS Breakers	$0	$0	$0	$0	$0	$0	$0	$0
Bronte TS CCRA True-up	$0	$0	$0	$0	$0	$0	$204,000	$0
General Service - Underground	$1,104,892	$2,141,202	$2,002,128	$2,504,181	$2,452,885	$3,869,996	$1,500,000	$1,500,000
General Service - Overhead	$1,259,668	$1,545,192	$1,397,859	$1,754,264	$1,738,037	$2,659,930	$1,408,000	$1,639,000
Subdivisions	$3,200,000	$1,979,932	$312,878	$1,517,358	$1,295,839	$0	$2,550,000	$2,350,000
MTO/City/Region Projects	$736,626	$117,068	$262,431	$532,810	$912,953	$65,317	$1,600,000	$2,430,000
Metrolinx Corridor Electrification	$0	$0	$0	$0	$0	$0	$1,100,000	$5,650,000
Burlington Mall 27.6kV Conversion/Relocation	$0	$0	$0	$0	$1,890,767	$0	$0	$0
Downtown Core Underground Development	$740,406	$21,592	$369,678	$0	$0	$281,022	$900,000	$800,000
Bridgewater Condominium	$0	$0	$0	$416,175	$9,385	$0	$0	$0
Washburn Reservoir	$0	$0	$0	$1,153,586	($10,300)	$0	$0	$0
Renewable Generation (FIT) SCADA	$0	$0	$0	$0	$44,841	$0	$0	$0
Transformers	$614,742	$1,035,329	$807,700	$666,397	$1,314,898	$1,494,168	$930,000	$930,000
Meters	$588,135	$658,237	$413,870	$582,506	$588,568	$590,086	$915,000	$847,500
Total Gross System Access	**$8,244,469**	**$7,498,551**	**$5,566,544**	**$9,127,277**	**$10,237,872**	**$9,960,519**	**$12,675,000**	**$16,146,500**
Contributed Capital	($3,550,000)	($4,345,542)	($1,849,513)	($4,387,988)	($4,654,703)	($3,015,487)	($6,225,000)	($10,779,000)
Total Net System Access	**$4,694,469**	**$3,153,009**	**$3,717,031**	**$4,739,289**	**$5,583,169**	**$6,945,032**	**$6,450,000**	**$5,367,500**

System Renewal

The key drivers for system renewal projects include programs to refurbish or replace asset systems at end of service life due to failure, failure risk, substandard performance, high performance risk or functional obsolescence. A summary of historical and proposed capital expenditures for system renewal projects is set out in Table 30 below.

Table 30 – Historical and Proposed Capital Expenditures – System Renewal

System Renewal Projects	2014 CoS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget
Recommission Substations	$90,299	$124,398	$54,197	$57,180	$57,810	$37,438	$53,000	$100,000
15MVA Station Transformer Replacement Program	$386,478	$0	$657,653	$721,917	$710,580	$530,699	$250,000	$275,000
Substation Automation (Vista)	$0	$0	$0	$0	$0	$0	$0	$0
Other Substation Renewal	$88,534	$48,751	$67,345	$0	$21,521	$21,450	$52,000	$345,000
Underground Rebuilds	$345,520	$957,007	$518,954	$175,274	$514,556	$303,081	$400,000	$500,000
Pole Replacement Program	$246,957	$104,475	$194,306	$111,107	$103,588	$187,440	$200,000	$510,000
Ontario Street Towers	$0	$0	$146,511	$9,909	$82,196	$37,516	$0	$0
Storm Damage	$0	$32,570	$172,581	$0	$205,821	$683,860	$0	$0
PCB Free Compliance - Transformer Replacement	$172,704	$63,846	$0	$0	$0	$0	$0	$0
Other System Renewal	$18,749	$8,266	$20,125	$67,017	$60,032	$92,085	$25,000	$25,000
Total Gross System Renewal	**$1,349,241**	**$1,339,313**	**$1,831,672**	**$1,142,404**	**$1,756,104**	**$1,893,569**	**$980,000**	**$1,755,000**
Contributed Capital	$0	$991	$0	($13,831)	($26,920)	($22,500)	$0	$0
Total Net System Renewal	**$1,349,241**	**$1,340,304**	**$1,831,672**	**$1,128,573**	**$1,729,184**	**$1,871,069**	**$980,000**	**$1,755,000**

System Service

The key drivers for system service projects include expected changes in load that constrain the ability of the system to provide consistent service delivery (e.g. capacity upgrade, line extensions); and system operational objectives (e.g. protection and control updates, automation, supervisory control and data acquisition). These investments are required to support the safety, reliability, quality and efficiency of the distribution system. A summary of historical and proposed capital expenditures for system service projects is set out in Table 31 below.

Table 31 – Historical and Proposed Capital Expenditures – System Service

System Service Projects	2014 CoS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget
Motorized ABS Program	$262,834	$175,864	$247,326	$28,630	$21,554	$25,515	$0	$280,000
NE Burlington TS Egress	$151,791	$1,309,345	$636,339	$341,261	$0	$73,497	$1,217,287	$1,000,000
Bronte Feeder Double CCT Egress	$420,290	$0	$0	$0	$0	$0	$0	$0
Port Nelson MS Switch Gear	$0	$0	$0	$0	$223,451	$0	$0	$0
Substation Upgrades	$73,625	$66,325	$100,733	$29,239	$43,079	$267,245	$55,000	$150,000
Total Gross System Service	**$908,540**	**$1,551,534**	**$984,398**	**$399,130**	**$288,085**	**$366,257**	**$1,272,287**	**$1,430,000**
Contributed Capital	($29,205)	($44,699)	($77,892)	$0	$0	($113,678)	$0	$0
Total Net System Service	**$879,335**	**$1,506,835**	**$906,506**	**$399,130**	**$288,085**	**$252,579**	**$1,272,287**	**$1,430,000**

General Plant

The key drivers for general plant projects include system capital investment support, system maintenance support, business operations efficiency, and non-distribution assets. A summary of historical and proposed capital expenditures for general plant projects is set out in Table 32 below.

Table 32 – Historical and Proposed Capital Expenditures – General Plant

General Plant Projects	2014 CoS	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Forecast	2020 Budget	
Buildings	$392,000	$210,877	$396,433	$269,940	$80,846	$518,025	$890,000	$420,000	
Vehicles	$50,000	$75,000	$419,587	$96,312	$633,245	$571,509	$667,000	$364,000	
Tools	$12,000	$106,711	$18,470	$26,951	$13,820	$10,099	$12,000	$12,000	
Office Equipment	$38,000	$50,890	$23,366	$53,959	$85,117	$57,670	$100,000	$58,500	
SCADA / GIS / AMI / OMS	$150,000	$592,914	$366,032	$199,346	$122,623	$88,740	$50,000	$575,000	*
Field Force Automation Enhancements	$20,000	$5,287	$0	$0	$0	$72,432	$41,000	$5,000	
Customer Information System and G/L	$20,000	$280,707	$203,545	$57,154	$69,972	$24,431	$25,000	$15,000	
Customer Information System (Replacement)	$0	$0	$0	$0	$0	$0	$0	$1,445,000	*
IBM Lease	$0	$0	$0	$265,958	$0	$0	$0	$0	
Other Computer Hardware & Software	$125,000	$94,442	$95,838	$144,741	$87,734	$287,416	$254,000	$318,000	
Total Gross General Plant	**$807,000**	**$1,416,828**	**$1,523,271**	**$1,114,361**	**$1,093,357**	**$1,630,322**	**$2,039,000**	**$3,212,500**	
Contributed Capital	$0	$0	$0	($8,633)	$0	$0	$0	$0	
Total Net General Plant	**$807,000**	**$1,416,828**	**$1,523,271**	**$1,105,728**	**$1,093,357**	**$1,630,322**	**$2,039,000**	**$3,212,500**	

Capital Project Descriptions and Expected in-service dates

Project 1: Customer Information System Replacement

Burlington Hydro is proceeding with the implementation of a new Customer Information System (CIS) with an estimated cost of $1.445M, as identified in Table 32 above. This project is an investment in critical customer service and billing infrastructure, and is not included in base rates. Burlington Hydro is seeking recovery through an ICM for this project.

Burlington Hydro's CIS (including an integrated Customer Portal) is a key enabler of customer service and billing capabilities. This strategic asset collects and stores customer account information and is the system of reference for providing prompt reply to customer inquiries. It supports the integrated delivery of customer care and revenue cycle processes, including meter data management, producing customers' bills and collecting revenues.

The main drivers of this investment are (i) technological obsolescence; (ii) the vendor no longer provides full CIS upgrades; and (iii) modifications in response to new public policy initiatives and regulatory changes are challenging, costly and time consuming. Burlington Hydro currently operates the Daffron CIS solution. This solution is 24 years old, was originally acquired and implemented in 1994-1995 and was based on mature technology at the time of purchase. Burlington Hydro's Daffron CIS has been heavily customized to meet the needs of the regulated Ontario electricity market, however, Daffron no longer provides full CIS upgrades in the Ontario market. Operating under the current CIS, Burlington Hydro expects to incur additional expenses and lost business operational efficiency as costly and challenging modifications are required in response to public policy and regulatory changes. Further, Burlington Hydro's customers have expressed their dissatisfaction and frustration with its current system and have been asking for more functionality for many years.

The project summary for Project 1: Customer Information System Replacement is attached as Appendix I and includes a description of need, options analyzed and prudence.

Project 2: Geographic Information System Replacement

Burlington Hydro is proceeding with the implementation of a new Geographic Information System (GIS) with an estimated cost of $500K, as included in the row titled "SCADA / GIS / AMI / OMS" in Table 32 above. This project is an investment in critical asset information infrastructure, and is not included in base rates. Burlington Hydro is seeking recovery through an ICM for this project.

Burlington Hydro's GIS is the central repository for all distribution asset information and is used by several departments across the organization. The GIS is the source database for several processes including Asset Data Collection and Asset Management, and feeds information directly to Burlington Hydro's Outage Management System.

Burlington Hydro's initiative to obtain a new GIS is driven by the software incompatibility and obsolescence of the current GIS, and by opportunities to improve business processes through new system functionality.

The project summary for Project 2: Geographic Information System Replacement is attached as Appendix J and includes a description of need, options analyzed and prudence.

Calculation of Revenue Requirement

The incremental revenue requirement associated with the ICM funding request of $1,945,000 is $140,286 as identified in Table 33 below, in total and by project. These calculations are provided in Tab "11. Incremental Capital Adj." of the ICM Module.

Table 33 – Incremental Revenue Requirement

Project Description	Total	CIS	GIS
Incremental Capital	$1,945,000	$1,445,000	$500,000
Incremental Capital (1/2 year rule)	$972,500	$722,500	$250,000
Return on Rate Base	$56,692	$42,118	$14,574
Amortization	$194,500	$144,500	$50,000
Incremental Grossed Up PILs	($110,905)	($82,395)	($28,510)
Total	**$140,286**	**$104,223**	**$36,063**

The Rate of Return has been calculated using the cost of capital parameters approved by the Board in Burlington Hydro's 2014 Cost of Service application (EB-2013-0115). Amortization has been calculated on a straight-line basis over the useful life of each asset as defined in the Accounting Procedures Handbook. The useful lives are consistent with those filed in Burlington Hydro's 2014 Cost of Service application (EB-2013-0115).

A half year of depreciation has been recovered which is consistent with the OEB's policy in ACM Report, and PILs have been calculated using a half year of Capital Cost Allowance ("CCA"). The OEB's policy per the September 18, 2014 ACM Report and the January 22, 2016 ACM/ICM Supplemental Report is that a full-year depreciation, CCA and return on capital is allowed for all years of the price cap plan except for the final year prior to rebasing, in which case the standard half-year rule is used for calculation of the return of (depreciation) and return on capital and associated taxers/PILs for the first year that an asset enters service. Since 2020 is the last year before Burlington Hydro's scheduled rebasing, it has used the "half-year" rule for the 2020 ICM-qualifying projects.

The detailed calculation of incremental revenue requirement is provided in the ICM Module filed as Attachment 9.

Incremental Project's Revenue Requirement offset by Other Means

None of the projects for which Burlington Hydro is requesting an ICM can be offset by revenue generated through other means (e.g. contributions in aid of construction); therefore Burlington Hydro has not provided a calculation of the revenue requirement offset associated with this.

Actions to be Taken in the Event that the ICM Applications are not Approved

Should the OEB not approve the application for the ICMs Burlington Hydro would need to reconsider its 2020 capital distribution expenditures and consider reductions to system service or system renewal, affecting system safety and reliability.

Calculation of Rate Riders

Burlington Hydro is seeking Board approval for the ICM rate riders, identified in Table 34 below, to recover the revenue requirement of $140,286 identified in Table 33 above. The revenue requirement has been allocated to rate classes based on the current allocation of revenue using Tab "8. Revenue Proportions" of the ICM Module filed as Attachment 9. The revenue requirement for the residential class will be recovered via a fixed rate rider as directed by the OEB in section 3.2.3 of the Chapter 3 Filing Requirements. Rate riders for all other rate classes are based on the current fixed/variable revenue split identified in Tabs 8 and 12 of the ICM Module. The rationale for this proposed rider design is that it is consistent with Burlington Hydro's rate design approved by the OEB in its 2014 Cost of Service application.

Table 34 – ICM Rate Riders

Rate Class	Fixed Rate Rider	Volumetric Rate Rider	Per Unit
RESIDENTIAL	$0.11	$0.0000	kWh
GENERAL SERVICE LESS THAN 50 kW	$0.12	$0.0001	kWh
GENERAL SERVICE 50 TO 4,999 kW	$0.28	$0.0135	kW
UNMETERED SCATTERED LOAD	$0.04	$0.0001	kWh
STREET LIGHTING	$0.00	$0.0204	kW

Table 35 below identifies the monthly bill impacts by rate class due to the incremental capital funding request.

Table 35 – ICM Monthly Bill Impacts

Rate Class	Unit	# Units	ICM Rate Rider before HST
RESIDENTIAL	kWh	700	$0.11
GENERAL SERVICE LESS THAN 50 kW	kWh	1,500	$0.27
GENERAL SERVICE 50 TO 4,999 kW	kW	200	$2.98
UNMETERED SCATTERED LOAD	kWh	2,000	$0.24
STREET LIGHTING	kW	100	$2.04

ICM Rate Rider Approved in 2019 IRM Application (EB-2018-0021)

Burlington Hydro received approval for incremental capital funding of $3.567M for the Tremaine TS CCRA true-up in its 2019 IRM Application (EB-2018-0021). This was based on a revised true-up estimate provided by Hydro One which was filed on February 21, 2019 as Attachment3_HONI_TremaineTS_CCRA_Trueup_20190221. Burlington Hydro also applied for, but was not approved for, incremental capital funding of $1.031M for the Bronte TS CCRA true-up. Subsequent to Hydro One providing these estimates, Burlington Hydro requested that Hydro One revisit the calculation of the true-up for both transformer stations as it was not in agreement with the Hydro One's allocation of load between transformer stations in the true-up calculation. As a result of this request, Hydro One revisited the calculation and finalized the true-up amounts for the Tremaine TS and Bronte TS CCRAs at $568.7K and $204.1K respectively.

Burlington Hydro is currently collecting a rate rider from customers for the Tremaine CCRA true-up based on an estimated capital expenditure of $3.567M, with an associated annual revenue requirement of $267,733. Burlington Hydro expects that this rate rider will be effective until April 30, 2021 as it plans to rebase for May 1, 2021 rates; this will generate revenue of $535,466 for two years from May 1, 2019 to April 30, 2021. The annual revenue requirement associated with the actual true-up amount of $568.7K is $42,632 as identified in Tab 11. "Incremental Capital Adj." of Attachment 10_ICM Module_FullYear_$569K_Tremaine CCRA_10102019. This generates revenue of $85,264 for two years from May 1, 2019 to April 30, 2021. Burlington Hydro expects that it will recover the revised revenue requirement of $85,264 by April 30, 2020. As such it requests that the rate rider for the Tremaine TS CCRA True-up (identified as "Rate Rider for Recovery of Incremental Capital Project 1 (2019)") be discontinued effective April 30, 2020 to avoid overcharging customers in the short-term. This rate rider would otherwise be in effect until Burlington Hydro rebases. Burlington Hydro recognizes that the amount would eventually be trued-up to ratepayers, however this approach avoids overcharging customers from May 1, 2020 to April 30, 2021 only to return the over collection in the period from May 1, 2021 to April 30, 2022.

Burlington Hydro does not wish to change the timing of the ICM true-up calculation which it intends to file in its 2021 Cost of Service application.

Bill Impacts

All rate payers in Burlington Hydro's service area will be affected by this Application. A summary of the bill impacts by rate class is provided in Tables 36 and 37 below. A detailed summary of the bill impacts for each rate class is provided as Appendix K.

Table 36 – Bill Impacts - Distribution Rates (excluding Pass-through)

Rate Class	RPP/ non-RPP	kWh	kW	Total Incr/(Decr) ($)	Total Incr/(Decr) (%)
RESIDENTIAL	RPP	700		$ 0.80	3.0%
GENERAL SERVICE LESS THAN 50 kW	RPP	1,500		$ 2.20	4.5%
GENERAL SERVICE 50 TO 4,999 kW	non-RPP	36,700	200	$ 31.55	4.5%
UNMETERED SCATTERED LOAD	RPP	2,000		$ 0.54	1.3%
STREET LIGHTING (1 CONNECTION)	non-RPP	175	0.22	$ 0.41	24.4%

Table 37 – Bill Impacts – Total Bill including HST

Rate Class	RPP/ non-RPP	kWh	kW	Total Incr/(Decr) ($)	Total Incr/(Decr) (%)
RESIDENTIAL	RPP	700		$ 0.58	0.6%
GENERAL SERVICE LESS THAN 50 kW	RPP	1,500		$ 1.84	0.9%
GENERAL SERVICE 50 TO 4,999 kW	non-RPP	36,700	200	$ 104.66	1.5%
UNMETERED SCATTERED LOAD	RPP	2,000		$ 0.71	0.3%
STREET LIGHTING (1 CONNECTION)	non-RPP	175	0.22	$ 0.72	2.7%

CONCLUSION

Burlington Hydro respectfully requests that the Board approve the relief sought in this Application.

APPENDICES

Appendix A – Current Tariff of Rates and Charges

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2019

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

EB-2018-0021

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	$	26.03
Rate Rider for Recovery of Wind Storm Damage Costs - effective until April 30, 2020	$	0.27
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.12
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.22
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until April 30, 2020	$/kWh	0.0003
Retail Transmission Rate - Network Service Rate	$/kWh	0.0071
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0064

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, 2019
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EB-2018-0021

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	$	26.57
Rate Rider for Recovery of Wind Storm Damage Costs - effective until April 30, 2020	$	0.65
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.13
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.23
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0142
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until April 30, 2020	$/kWh	0.0005
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0057

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

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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	$	62.29
Rate Rider for Recovery of Wind Storm Damage Costs - effective until April 30, 2020	$	6.63
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.30
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.53
Distribution Volumetric Rate	$/kW	3.0664
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until April 30, 2020	$/kW	0.0629
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kW	0.0263

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Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kW	0.0148
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.8046
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.4996

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.

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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	$	9.55
Rate Rider for Recovery of Wind Storm Damage Costs - effective until April 30, 2020	$	0.18
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.05
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.08
Distribution Volumetric Rate	$/kWh	0.0166
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until April 30, 2020	$/kWh	(0.0003)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0057

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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.

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STREET LIGHTING SERVICE CLASSIFICATION

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

APPLICATION

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

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

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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	$	0.64
Rate Rider for Recovery of Wind Storm Damage Costs - effective until April 30, 2020	$	0.01
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.01
Distribution Volumetric Rate	$/kW	4.6183
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2019) - effective until April 30, 2020	$/kW	(0.0254)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kW	0.0397
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kW	0.0222
Retail Transmission Rate - Network Service Rate	$/kW	2.0496
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.7789

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, 2019
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EB-2018-0021

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

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ALLOWANCES

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

SPECIFIC SERVICE CHARGES

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

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

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

Customer Administration

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

Non-Payment of Account (see Note below)

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect 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	$	43.63
(with the exception of wireless attachments)		

NOTE: Ontario Energy Board Rate Order EB-2017-0183, issued on March 14, 2019, identifies changes to the Non-Payment of Account Service Charges effective July 1, 2019

Burlington Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2019

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

EB-2018-0021

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	$	100.00
Monthly Fixed Charge, per retailer	$	40.00
Monthly Variable Charge, per customer, per retailer	$/cust.	1.00
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.60
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.60)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.50
Processing fee, per request, applied to the requesting party	$	1.00
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)	$	4.00
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)	$	2.00

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	1.0373
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0270

Appendix B – Proposed Tariff of Rates and Charges

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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	$	26.30
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$	0.11
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.12
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.22
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until April 30, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0009
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	(0.0008)
Rate Rider for Disposition of Capacity Based Recovery Account (2020) - effective until April 30, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0076
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0068

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

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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	$	26.85
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$	0.12
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.13
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.23
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0143
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until April 30, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	0.0015
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	(0.0007)
Rate Rider for Disposition of Capacity Based Recovery Account (2020) - effective until April 30, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0073
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

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, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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	$	62.94
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$	0.28
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.30
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.53
Distribution Volumetric Rate	$/kW	3.0986

Burlington Hydro Inc.
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Rate Rider for Disposition of Global Adjustment Account (2020) - effective until April 30, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	0.1703
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	(0.2452)
Rate Rider for Disposition of Capacity Based Recovery Account (2020) - effective until April 30, 2021 Applicable only for Class B Customers	$/kW	(0.0300)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kW	0.0263
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kW	0.0148
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$/kW	0.0135
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.9906
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.6704

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, 2020

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

EB-2019-0023

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	$	9.65
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$	0.04
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$	0.05
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.08
Distribution Volumetric Rate	$/kWh	0.0168
Rate Rider for Disposition of Capacity Based Recovery Account (2020) - effective until April 30, 2021 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kWh	(0.0004)
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kWh	(0.0007)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$/kWh	0.0001
Retail Transmission Rate - Network Service Rate	$/kWh	0.0073
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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	$	0.65
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$	0.00
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$	0.01
Distribution Volumetric Rate	$/kW	4.6668
Rate Rider for Disposition of Global Adjustment Account (2020) - effective until April 30, 2021 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until April 30, 2021	$/kW	1.7199
Rate Rider for Disposition of Deferral/Variance Accounts (2020) - effective until April 30, 2021	$/kW	(0.2623)
Rate Rider for Disposition of Capacity Based Recovery Account (2020) - effective until April 30, 2021 Applicable only for Class B Customers	$/kW	(0.0300)
Rate Rider for Recovery of Incremental Capital Project 1 (2019) - effective until the next cost of service based rate order	$/kW	0.0397
Rate Rider for Recovery of Incremental Capital Project 2 (2019) - effective until the next cost of service based rate order - Implemented December 1, 2019	$/kW	0.0222
Rate Rider for Recovery of Incremental Capital - effective until the next cost of service based rate order	$/kW	0.0204
Retail Transmission Rate - Network Service Rate	$/kW	2.1855
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.9005

MONTHLY RATES AND CHARGES - Regulatory Component

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

		EB-2019-0023
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, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

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

Burlington Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2020
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2019-0023

Non-Payment of Account (see Note below)

Late payment - per month	%	1.50
Late payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/reconnect at meter - during regular hours	$	65.00
Disconnect/reconnect 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)	$	44.15

NOTE: Ontario Energy Board Rate Order EB-2017-0183, issued on March 14, 2019, identifies changes to the Non-Payment of Account Service Charges effective July 1, 2019

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	$	101.20
Monthly Fixed Charge, per retailer	$	40.48
Monthly Variable Charge, per customer, per retailer	$/cust.	1.01
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.61
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.61)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.51
Processing fee, per request, applied to the requesting party	$	1.01
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)	$	4.05
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)	$	2.00

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	1.0373
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.027

Appendix C – Certification of Evidence

CERTIFICATION OF THE EVIDENCE

EB-2019-0023

General Certification

As President and Chief Executive Officer of Burlington Hydro Inc. I certify, that to the best of my knowledge, the evidence filed in support of this Application is accurate and complete; and complies with Chapter 1 and Chapter 3 of the Board's *Filing Requirements for Electricity Distribution Rate Applications – 2018 Edition for 2019 Rate Applications* issued on July 12, 2018 and *the Addendum to Filing Requirements for Electricity Distribution Rate Applications – 2020 Rate Applications* dated July 15, 2019.

Gerry Smallegange
President and Chief Executive Officer
Burlington Hydro Inc.

Deferral and Variance Account Balances

As Chief Financial Officer of Burlington Hydro Inc. I certify, that to the best of my knowledge, Burlington Hydro Inc. has robust processes and internal controls in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed, consistent with the certification requirements in Chapter 1 of the filing requirements.

Michael Kysley
Executive Vice President and Chief Financial Officer
Burlington Hydro Inc.

Appendix D – GA Analysis Workform

Ontario Energy Board

GA Analysis Workform

Version 1.9

Account 1589 Global Adjustment (GA) Analysis Workform

Input cells
Drop down cells

Utility Name BURLINGTON HYDRO INC.

Note 1 **Please select "Yes" in column D for any year being requested for disposition**

2014	No
2015	No
2016	No
2017	Yes
2018	Yes

Note 7 **Summary of GA (if multiple years requested for disposition)**

Year	Annual Net Change in Expected GA Balance from GA Analysis	Net Change in Principal Balance in the GL	Reconciling Items	Adjusted Net Change in Principal Balance in the GL	Unresolved Difference	$ Consumption at Actual Rate Paid	Unresolved Difference as % of Expected GA Payments to IESO
2017	$ 1,105,942	$ 914,852	$ 795,682	$ 1,710,534	$ 604,592	$ 69,455,496	0.9%
2018	$ (1,089,002)	$ (818,805)	$ (88,582)	$ (907,387)	$ 181,616	$ 54,327,011	0.3%
Cumulative Balance	**$ 16,940**	**$ 96,047**	**$ 707,101**	**$ 803,148**	**$ 786,208**	**$ 123,782,507**	**N/A**

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2017		
Total Metered excluding WMP	C = A+B	1,557,033,292	kWh	100%
RPP	A	762,645,853	kWh	49.0%
Non RPP	B = D+E	794,387,439	kWh	51.0%
Non-RPP Class A	D	126,515,929	kWh	8.1%
Non-RPP Class B*	E	667,871,510	kWh	42.9%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Please confirm that the above RRR data is accurate Confirmed

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year **2017**

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	64,487,894	62,539,541	66,959,257	68,907,610	0.06687	$ 4,607,852	0.08227	$ 5,669,029	$ 1,061,177
February	69,448,358	66,959,257	57,585,208	60,074,309	0.10559	$ 6,343,246	0.08639	$ 5,189,820	$ (1,153,427)
March	59,733,139	57,585,208	52,940,201	55,088,132	0.08409	$ 4,632,361	0.07135	$ 3,930,538	$ (701,823)
April	63,947,519	52,940,201	48,295,040	59,302,358	0.06874	$ 4,076,444	0.10778	$ 6,391,608	$ 2,315,164
May	61,526,409	48,295,040	52,566,675	65,798,044	0.10623	$ 6,989,726	0.12307	$ 8,097,765	$ 1,108,039
June	62,828,237	52,566,675	55,589,119	65,850,682	0.11954	$ 7,871,790	0.11848	$ 7,801,989	$ (69,802)
July	67,289,526	55,589,119	49,501,800	61,202,207	0.10652	$ 6,519,259	0.11280	$ 6,903,609	$ 384,350
August	53,876,161	49,501,800	42,851,617	47,225,979	0.11500	$ 5,430,988	0.10109	$ 4,774,074	$ (656,913)
September	54,215,639	42,851,617	42,302,082	53,666,104	0.12739	$ 6,836,525	0.08864	$ 4,756,963	$ (2,079,562)
October	51,499,814	42,302,082	39,402,823	48,600,555	0.10212	$ 4,963,089	0.12563	$ 6,105,688	$ 1,142,599
November	49,054,618	39,402,823	38,427,689	48,079,484	0.11164	$ 5,367,594	0.09704	$ 4,665,633	$ (701,960)
December	47,774,612	38,427,689	46,792,754	56,139,676	0.08391	$ 4,710,680	0.09207	$ 5,168,780	$ 458,100
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**705,681,926**	**608,961,051**	**593,214,264**	**689,935,139**		**$ 68,349,554**		**$ 69,455,496**	**$ 1,105,942**

Calculated Loss Factor **1.0330**

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments		
				Principal Adjustment on DVA Continuity Schedule	If "no", please provide an explanation	$ Principal Adjustment on DVA Continuity Schedule
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		$ 914,852				
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year	$ 681,404	Remove correction related to 2016 activity (identified on page 21 of EB-2017-0029)	Yes		$ 681,404
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year					
2a	Remove prior year end unbilled to actual revenue differences					
2b	Add current year end unbilled to actual revenue differences					
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	$ 5,531	Increase to 2016 GA revenues recorded in 2017	No	Immaterial	
3b	Add difference between current year accrual/forecast to actual from long term load transfers	$ 281	Increase to prior years GA expenses recorded in 2018	No	Immaterial	
4	Remove GA balances pertaining to Class A customers					
5	Significant prior period billing adjustments recorded in current year	$ 121,151	Deduct 2016 Billing Adjustment (increase to revenue) made in 2017 ($121,151); 2017 billing adjustments made in 2018 are immaterial (<$1,000)	No	Adj. in 2017 DVA & not in 2016 DVA	
6	Differences in GA IESO posted rate and rate charged on IESO invoice	$ 20,464		No	Immaterial	
7	Differences in actual system losses and billed TLFs	$ (33,148)		No	Immaterial	
8	Others as justified by distributor					
9						
10						
				Total Principal Adjustments on DVA Continuity Schedule		$ 681,404

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ 1,710,534
	Net Change in Expected GA Balance in the Year Per Analysis	$ 1,105,942
	Unresolved Difference	$ 604,592
	Unresolved Difference as % of Expected GA Payments to IESO	0.9%

Ontario Energy Board

GA Analysis Workform

Note 2 **Consumption Data Excluding for Loss Factor (Data to agree with RRR as applicable)**

Year		2018		
Total Metered excluding WMP	C = A+B	1,597,636,816	kWh	100%
RPP	A	808,942,246	kWh	50.6%
Non RPP	B = D+E	788,694,570	kWh	49.4%
Non-RPP Class A	D	211,575,464	kWh	13.2%
Non-RPP Class B*	E	577,119,106	kWh	36.1%

*Non-RPP Class B consumption reported in this table is not expected to directly agree with the Non-RPP Class B Including Loss Adjusted Billed Consumption in the GA Analysis of Expected Balance table below. The difference should be equal to the loss factor.

Please confirm that the above RRR data is accurate Confirmed

Note 3 **GA Billing Rate**

GA is billed on the 1st Estimate

Please confirm that the GA Rate used for unbilled revenue is the same as the one used for billed revenue in any paticular month Yes

Note 4 **Analysis of Expected GA Amount**

Year 2018

Calendar Month	Non-RPP Class B Including Loss Factor Billed Consumption (kWh)	Deduct Previous Month Unbilled Loss Adjusted Consumption (kWh)	Add Current Month Unbilled Loss Adjusted Consumption (kWh)	Non-RPP Class B Including Loss Adjusted Consumption, Adjusted for Unbilled (kWh)	GA Rate Billed ($/kWh)	$ Consumption at GA Rate Billed	GA Actual Rate Paid ($/kWh)	$ Consumption at Actual Rate Paid	Expected GA Variance ($)
	F	G	H	I = F-G+H	J	K = I*J	L	M = I*L	=M-K
January	49,946,124	48,538,124	41,902,986	43,310,986	0.08777	$ 3,801,405	0.06736	$ 2,917,428	$ (883,977)
February	52,734,153	41,902,986	37,945,762	48,776,929	0.07333	$ 3,576,812	0.08167	$ 3,983,612	$ 406,800
March	47,135,059	37,945,762	39,001,371	48,190,668	0.07877	$ 3,795,979	0.09481	$ 4,568,957	$ 772,978
April	49,429,658	39,001,371	37,443,909	47,872,196	0.09810	$ 4,696,262	0.09959	$ 4,767,592	$ 71,330
May	46,034,600	37,443,909	39,535,334	48,126,025	0.09392	$ 4,519,996	0.10793	$ 5,194,242	$ 674,246
June	49,287,060	39,535,334	40,413,263	50,164,989	0.13336	$ 6,690,003	0.11896	$ 5,967,627	$ (722,376)
July	50,766,971	40,413,263	44,563,646	54,917,354	0.08502	$ 4,669,073	0.07737	$ 4,248,956	$ (420,118)
August	55,116,704	44,563,646	62,039,095	72,592,153	0.07790	$ 5,654,929	0.07490	$ 5,437,152	$ (217,776)
September	56,388,930	62,039,095	52,935,616	47,285,451	0.08424	$ 3,983,326	0.08584	$ 4,058,983	$ 75,657
October	49,489,133	52,935,616	42,137,194	38,690,711	0.08921	$ 3,451,598	0.12059	$ 4,665,713	$ 1,214,115
November	47,582,648	42,137,194	42,025,653	47,471,107	0.12235	$ 5,808,090	0.09855	$ 4,678,278	$ (1,129,812)
December	45,632,245	42,025,653	48,236,617	51,843,209	0.09198	$ 4,768,538	0.07404	$ 3,838,471	$ (930,067)
Net Change in Expected GA Balance in the Year (i.e. Transactions in the Year)	**599,543,285**	**528,481,953**	**528,180,446**	**599,241,778**		**$ 55,416,013**		**$ 54,327,011**	**$ (1,089,002)**

Calculated Loss Factor **1.0383**

Note 5 **Reconciling Items**

	Item	Amount	Explanation	Principal Adjustments		
				Principal Adjustment on DVA Continuity Schedule	If "no", please provide an explanation	$ Principal Adjustment on DVA Continuity Schedule
Net Change in Principal Balance in the GL (i.e. Transactions in the Year)		$ (818,805)				
1a	True-up of GA Charges based on Actual Non-RPP Volumes - prior year					
1b	True-up of GA Charges based on Actual Non-RPP Volumes - current year					
2a	Remove prior year end unbilled to actual revenue differences					
2b	Add current year end unbilled to actual revenue differences					
3a	Remove difference between prior year accrual/forecast to actual from long term load transfers	$ (281)	Increase to prior years GA expenses recorded in 2018	No	Immaterial	
3b	Add difference between current year accrual/forecast to actual from long term load transfers		Not required - accrued to actual at year-end			
4	Remove GA balances pertaining to Class A customers					
5	Significant prior period billing adjustments recorded in current year					
6	Differences in GA IESO posted rate and rate charged on IESO invoice	$ 6,222		No	Immaterial	
7	Differences in actual system losses and billed TLFs	$ (94,523)		No	Immaterial	
8	Others as justified by distributor					
9						
10						
					Total Principal Adjustments on DVA Continuity Schedule	$ -

Note 6	**Adjusted Net Change in Principal Balance in the GL**	$ (907,387)
	Net Change in Expected GA Balance in the Year Per Analysis	$ (1,089,002)
	Unresolved Difference	$ 181,616
	Unresolved Difference as % of Expected GA Payments to IESO	0.3%

Appendix E – GA Methodology Description

GA Methodology Description
Questions on Accounts 1588 & 1589

1. Please complete the Table below for principal adjustments on the DVA Continuity Schedule for Account 1588.

Burlington Hydro has completed Table 1 below for both 2017 and 2018 since it has not disposed of 2017 balances.

Table 1

Description	2018		2017	
	Principal Adjustments	Was the amount a "Principal Adjustment" in the previous year? (Y/N)	Principal Adjustments	Was the amount a "Principal Adjustment" in the previous year? (Y/N)
Balance December 31, 2018				
Reversals of Principal Adjustments - previous year				
1. Reversal of Cost of Power accrual from previous year				
2. Reversal of CT 1142 true-up from the previous year				
3. Unbilled to billed adjustment for previous year				
4. Reversal of RPP vs. Non-RPP allocation			($624,435)	Y
Sub-Total Reversals from previous year (A):			($624,435)	
Principal Adjustments - current year				
5. Cost of power accrual for 2018 vs Actual per IESO bill				
6. True-up of CT 1142 for 2018 consumption recorded in 2019 GL				
7. Unbilled accrued vs. billed for 2018 consumption				
8. True-up of RPP vs. Non-RPP allocation of CT 148 based on actual 2018 consumption			($2,173,966)	N
9. Other				
Sub-Total Principal Adjustments for 2018 consumption (B)			($2,173,966)	
Total Principal Adjustments shown for 2018 (A + B)			($2,798,401)	
Bal. For Disposition - 1588 (should match Total Claim column on DVA Continuity Schedule)	($346,857)		$948,027	

2. **In booking expense journal entries for Charge Type (CT) 1142 and CT 148 from the IESO invoice, please confirm which of the following approaches is used:**
   a. CT 1142 is booked into Account 1588. CT 148 is pro-rated based on RPP/non-RPP consumption and then booked into Account 1588 and 1589 respectively.
   b. CT 148 is booked into Account 1589. The portion of CT 1142 equaling RPP minus HOEP for RPP consumption is booked into Account 1588. The portion of CT 1142 equaling GA RPP is credited into Account 1589.
   c. If another approach is used, please explain in detail.
   d. Was the approach described in response to the above questions used consistently for all years for which variances are proposed for disposition? If not, please discuss.

<u>Burlington Hydro's response:</u>

In booking expense journal entries for Charge Type 1142 (RPP vs. Market Price Settlement Claim), and Charge Type 148 (Class B Global Adjustment Settlement Amount) from the IESO invoice, Burlington Hydro uses another approach as follows:

Charge Type 1142 is booked into Account 1588. For Charge Type 148, the entire amount is initially booked to Account 1589. The GA attributable to RPP customers (the RPP quantities multiplied by the GA rate on the IESO invoice) is subsequently credited to Account 1589 and booked to Account 1588. Burlington Hydro notes that this approach is a residual method similar to approach b) but generates the same result as approach a).

Yes the approach described in response to the above questions has been used consistently for all years for which variances are proposed for disposition.

3. **Questions on CT 1142**
   a. Please describe how the initial RPP related GA is determined for settlement forms submitted by day 4 after the month-end (resulting in CT 1142 on the IESO invoice).
   b. Please describe the process for truing up CT 1142 to actual RPP kWh, including which data is used for each TOU/Tier 1&2 prices, as well as the timing of the true up.
   c. Has CT 1142 been trued up for with the IESO for all of 2018?
   d. Which months from 2018 were trued up in 2019?

i. Were these true ups recorded in the 2018 or 2019 balance in the General Ledger?

e. Have all of the 2018 related true-ups been reflected in the applicant's DVA Continuity Schedule in this proceeding?

Burlington Hydro's response:

a. The process to determine the initial RPP related GA for settlement forms submitted by day 4 after the month-end is described in Table 16 and on page 27 of Burlington Hydro's 2020 IRM Application EB-2019-0023.
b. The process for truing up CT 1142 to actual RPP kWh, including which data is used for each TOU/Tier 1&2 prices, as well as the timing of the true up is described in Table 16 and on page 27 of Burlington Hydro's 2020 IRM Application EB-2019-0023.
c. Yes, CT 1142 has been trued up for with the IESO for all of 2018.
d. December 2018 was trued up in 2019 with the IESO
    i. This true-up was recorded in the 2018 balance in the General Ledger.
e. Yes all of the 2018 related true-ups have been reflected in Burlington Hydro's DVA Continuity Schedule.

4. Questions on CT 148

a. Please describe the process for the initial recording of CT 148 in the accounts (i.e. 1588 and 1589).
b. Please describe the process for true up of the GA related cost to ensure that the amounts reflected in Account 1588 are related to RPP GA costs and amounts in 1589 are related to only non-RPP GA costs.
c. What data is used to determine the non-RPP kWh volume that is multiplied with the actual GA per kWh rate (based on CT 148) for recording as the initial GA expense in Account 1589?
d. Does the utility true up the initial recording of CT 148 in Accounts 1588 and 1589 based on estimated RPP/non-RPP consumption proportions to actuals based on actual RPP-non-RPP consumption proportions?
e. Please indicate which months from 2018 were trued up in 2019 for CT 148 proportions between RPP and non-RPP
    i. Were these true ups recorded in the 2018 or 2019 balance in the General Ledger?

f. Are all true-ups for 2018 consumption reflected in the DVA Continuity Schedule?

Burlington Hydro's response:

a. Please see the response to Question 2.
b. Please refer to page 27 and 28 of Burlington Hydro's 2020 IRM application EB-2019-0023 for the true-up process for Account 1588. Burlington Hydro does not have a true-up for Account 1589. Actual GA costs are initially booked to Account 1589 based on the IESO actual GA and actual consumption where available.
c. Burlington Hydro uses actual consumption where known (Class A and non-RPP interval metered customers billed at spot) and an estimate of consumption for non-RPP non-interval Metered and Retailer customers billed at spot. This is identified in Table 16 of Burlington Hydro's 2020 IRM application EB-2019-0023.
d. Yes, Burlington Hydro trues up the initial recording of CT 148 in Accounts 1588 and 1589 based on estimated RPP/non-RPP consumption proportions. However, Burlington Hydro does not have access to actual consumption proportions in its Customer Information System. It uses its best estimate of RPP/non-RPP consumption proportions.
e. December 2018 was trued up in 2019 with the IESO
    i. This true-up was recorded in the 2018 balance in the General Ledger.
g. Yes all of the 2018 related true-ups have been reflected in the DVA Continuity Schedule.

5. Questions regarding principal adjustments and reversals on the DVA Continuity Schedule:

<u>Questions on Principal Adjustments - Accounts 1588 and 1589</u>

a. Did the applicant have principal adjustments in its 2019 rate proceeding which were approved for disposition?

b. If yes, please provide a break-down of the total amount of principal adjustments that were approved (e.g. true-up of unbilled, true up of CT 1142, true up of CT 148 etc.) for each of Accounts 1588 and 1589.

c. Has the applicant reversed the adjustment approved in 2019 rates in its current proposed amount for disposition?

NB: only the principal adjustments amounts that were disposed in the previous proceeding should be reversed in this proceeding. For example, if no amount related to unbilled to billed adjustment for 2018 consumption was included in 2019 proceeding, this amount should <u>not</u> be included as a “reversal” from previous year.

d. Please confirm that the allocation of charge type 148 has been trued up to actual proportion of RPP/non-RPP consumption in the GL.

Burlington Hydro’s response:

Burlington Hydro provides a response to this question for its 2018 rate proceeding as it did not dispose of any balances in its 2019 rate proceeding; therefore its 2019 rate proceeding is not applicable.

a. Yes, Burlington Hydro had principal adjustments in its 2018 rate proceeding which were approved for disposition.

b. Burlington Hydro provided Table 10 in its 2018 IRM Application (EB-2017-0029) which identified the breakdown of the total amount of principal adjustments that were approved. This table is reproduced below for ease of reference.

Table 2

Description	$RSVA_{GA}$	$RSVA_{POWER}$
2016 Opening Principal Balance	**$3,880,959**	**($512,289)**
Principal Activity in RSVA	($897,458)	($1,786,540)
2016 Closing Principal Balance	**$2,983,501**	**($2,298,829)**
RPP vs. non-RPP Consumption Adjustment	($681,404)	$681,404
RPP vs. Market Price Claim		($56,969)
Adjusted 2016 Closing Principal Balance	**$2,302,097**	**($1,674,394)**

c. Yes, Burlington Hydro reversed the adjustment approved in 2018 rates in its current proposed amount for disposition.

d. Burlington Hydro confirms that the allocation of charge type 148 has been trued up to its best estimate of the proportion of RPP/non-RPP consumption. Please see response to 4(d).

Appendix F – 1595 Analysis Workform

Ontario Energy Board

1595 Analysis Workform

Version 1.0

Account 1595 Analysis Workform

Input cells	
Drop down cells	

Utility Name Burlington Hydro Inc.

Utility name must be selected

Please select "yes" for the 1595 Rate Years being Requested for Disposition

2012	No
2013	No
2014	No
2015	No
2016	Yes
2017	Yes

Ontario Energy Board

1595 Analysis Workform

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$737,091	$2,435,445	$1,698,354	$1,696,169	$2,185	-$28,097	**-$25,912**	**0.1%**
Account 1589 - Global Adjustment		$1,432,328	-$25,300	$1,407,028	$1,382,039	$24,989	$9,824	**$34,813**	**1.8%**
Total Group 1 and Group 2 Balances		$695,237	$2,410,145	$3,105,382	$3,078,208	$27,174	-$18,273	**$8,901**	**0.9%**
							Total residual balance per continuity schedule:	$8,901	
							Difference (any variance should be explained):	**$0**	

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Additional Notes and Comments

Ontario Energy Board

1595 Analysis Workform

Step 1

Components of the 1595 Account Balances:		Principal Balance Approved for Disposition	Carrying Charges Balance Approved for Disposition	Total Balances Approved for Disposition	Rate Rider Amounts Collected/(Returned)	Residual Balances Pertaining to Principal and Carrying Charges Approved for Disposition	Carrying Charges Recorded on Net Principal Account Balances	Total Residual Balances	Collections/Returns Variance (%)	
Total Group 1 and Group 2 Balances excluding Account 1589 - Global Adjustment		-$4,562,938	-$113,086	-$4,676,024	-$4,039,274	-$636,749	-$25,604	**-$662,353**	**13.6%**	Calculated differences of greater than + or -
Account 1589 - Global Adjustment		$2,448,630	$45,384	$2,494,014	$2,208,226	$285,788	$21,343	**$307,131**	**11.5%**	Calculated differences of greater than + or -
Total Group 1 and Group 2 Balances		-$2,114,308	-$67,702	-$2,182,010	-$1,831,049	-$350,961	-$4,261	**-$355,222**	**16.1%**	
							Total residual balance per continuity schedule:	-$355,222		
							Difference (any variance should be explained):	**$0**		

*Unresolved differences of +/- 10% require further analysis and explanation. Amounts originally approved for disposition based on forecasted consumption or number of customers must be compared to actual figures.

Step 2

Select Rate Rider(s) Applicable for 1595 Recovery Period by indicating "Yes" in column G

Rate Rider- Group 1 DVA Accounts (Excluding Global Adjustment)	Yes
Rate Rider- Group 1 DVA Accounts (Excluding Global Adjustment) - Non-WMP	No
Rate Rider - RSVA - Global Adjustment	Yes
Rate Rider - RSVA - Group 2 Accounts (If a separate Group 2 rate rider was created)	No
Other 1	Yes
Other 2	No
Other 3	No

Step 3

RATE RIDER - GROUP 1 DVA ACCOUNTS (EXCLUDING GLOBAL ADJUSTMENT)

Rate Rider Recovery Period (Months) 12

Data used to calculate rate rider (Data to agree with Rate Generator Model and OEB Decision as applicable for the vintage year) versus actuals

Rate Class	Unit	Allocated Balance to Rate Class as Approved by OEB	Denominator Used in Rider Calculation as Approved by OEB (annualized)	Calculated Rate Rider as Approved by OEB	Projected Consumption over Recovery Period	Billed Consumption (kWh/kW) that the rider was applied against**	Forecasted versus billed Consumption Variance (kWh/kW)	Calculated Variance ($)	Calculated Variance (%)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	($1,709,083)	529,430,951	($0.0032)	529,430,951	506,415,969	23,014,982	($73,648)	4.3%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	($544,500)	168,383,559	($0.0032)	168,383,559	167,299,371	1,084,188	($3,469)	0.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	($2,924,770)	2,390,334	($1.2236)	2,390,334	2,378,296	12,038	($14,730)	0.5%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	($9,985)	3,091,043	($0.0032)	3,091,043	3,133,198	-42,155	$135	-1.4%
STREET LIGHTING SERVICE CLASSIFICATION	kW	($32,232)	27,667	($1.1650)	27,667	25,189	2,478	($2,887)	9.0%
microFIT SERVICE CLASSIFICATION									
TOTAL		**($5,220,570)**						**($94,599)**	**1.8%**

**Data for billed consumption should not be materially different from data submitted in RRR 2.1.5.4 filings. Please refer to RRR 2.1.5.4 filings to ensure billed consumption data is reasonably accurate.
There may be differences due to unbilled revenue accruals, recovery period dates, or other factors. However, any substantial deviations between billed consumption that the rider was applied against and billed consumption reported in RRR can be an indicator of rider misallocations or errors in the data used in the workform.

RATE RIDER - RSVA - GLOBAL ADJUSTMENT

Rate Rider Recovery Period (Months) 12

Data used to calculate rate rider (Data to agree with Rate Generator Model and OEB Decision as applicable for the vintage year) versus actuals

Rate Class	Unit	Allocated Balance to Rate Class as Approved by OEB	Denominator Used in Rider Calculation as Approved by OEB (annualized)	Calculated Rate Rider as Approved by OEB	Projected Consumption over Recovery Period	Billed Consumption (kWh/kW) that the rider was applied against**	Forecasted versus billed Consumption Variance (kWh/kW)	Calculated Variance ($)	Calculated Variance (%)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	$49,935	16,766,066	$0.0030	16,766,066	9,369,182	7,396,884	$22,191	44.4%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	$79,072	26,549,019	$0.0030	26,549,019	22,749,846	3,799,173	$11,398	14.4%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kWh	$2,277,227	764,597,904	$0.0030	764,597,904	703,222,973	61,374,931	$184,125	8.1%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION									
STREET LIGHTING SERVICE CLASSIFICATION	kWh	$29,403	9,872,218	$0.0030	9,872,218	8,914,151	958,067	$2,874	9.8%
microFIT SERVICE CLASSIFICATION									
TOTAL		**$2,435,637**						**$220,587**	**9.1%**

**Data for billed consumption should not be materially different from data submitted in RRR 2.1.5.4 filings. Please refer to RRR 2.1.5.4 filings to ensure billed consumption data is reasonably accurate.
There may be differences due to unbilled revenue accruals, recovery period dates, or other factors. However, any substantial deviations between billed consumption that the rider was applied against and billed consumption reported in RRR can be an indicator of rider misallocations or errors in the data used in the workform.

Other 1 - LRAM

Rate Rider Recovery Period (Months) 12

Data used to calculate rate rider (Data to agree with Rate Generator Model and OEB Decision as applicable for the vintage year) versus actuals

Rate Class	Unit	Allocated Balance to Rate Class as Approved by OEB	Denominator Used in Rider Calculation as Approved by OEB (annualized)	Calculated Rate Rider as Approved by OEB	Projected Consumption / # customers over recovery period	Billed Consumption / # of customers that the rider was applied against**	Forecasted versus billed consumption / # of customers variance	Calculated Variance ($)	Calculated Variance (%)
RESIDENTIAL SERVICE CLASSIFICATION	kWh	$189,839	529,430,951	$0.0004	529,430,951	506,416,406	23,014,545	$9,206	4.8%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	$218,908	168,383,559	$0.0013	168,383,559	167,299,371	1,084,188	$1,409	0.6%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	$108,164	2,390,334	$0.0453	2,390,334	2,378,296	12,038	$545	0.5%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	($588)	3,091,043	($0.0002)	3,091,043	3,133,198	-42,155	$8	-1.4%
STREET LIGHTING SERVICE CLASSIFICATION	kW	($1,560)	27,667	($0.0564)	27,667	25,189	2,478	($140)	9.0%
microFIT SERVICE CLASSIFICATION									
TOTAL		**$514,763**						**$11,029**	**2.1%**

**Data for billed consumption should not be materially different from data submitted in RRR 2.1.5.4 filings. Please refer to RRR 2.1.5.4 filings to ensure billed consumption data is reasonably accurate.
There may be differences due to unbilled revenue accruals, recovery period dates, or other factors. However, any substantial deviations between billed consumption that the rider was applied against and billed consumption reported in RRR can be an indicator of rider misallocations or errors in the data used in the workform.

SUMMARY	
Total Calculated Account Balance	$137,018
Total Account Residual Balance per Step 1 above	($350,961)
Unreconciled Differences* **	$487,979

***Any unreconciled difference between amounts reported in the residual balances section in Step 1 and amounts calculated for the total of all applicable riders in Step 3 must be explained.

Additional Notes and Comments

Unreconciled Difference of $487,979 is made up of the following and identified in the Application:

2017 IRM (EB-2016-0059) CBR Class B over recovery of $452,213 (disposition amount included in DVA rate rider & CBR rate rider)
2017 IRM (EB-2016-0059) Tax Share Amount transferred to account 1595 $(29,784)
Prior Year residual balances not cleared $65,550

Appendix G – IndEco 2017-2018 LRAMVA Report

IndEco

Strategic Solutions for a Changing World™

Burlington Hydro Inc.
2017-2018 LRAMVA

Burlington Hydro Inc. lost revenue related to Conservation and Demand Management

2017-2018

IndEco

This document was prepared for Burlington Hydro Inc. by IndEco Strategic Consulting Inc.

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IndEco report B9170
9 October 2019

Contents

Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

Burlington Hydro Inc. (BHI) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period. BHI is required to use "the most recent and appropriate final CDM evaluation report from the IESO in support of its lost revenue calculation."[2]

Normally, the IESO releases adjustments to previous year values with each annual report. Due to direction from the Province, the IESO announced that it would not be providing an annual verified report for 2018. On July 15, 2019, the OEB released a document *Addendum to Filing Requirements for Electricity Distribution Rate Applications: 2020 Rate Applications* which instructs LDCs to base savings subsequent to the 2017 final verified report on the IESO Participation and Cost Reports. These are used to determine the 2017 True-up values and 2018 net results.

BHI may claim lost revenue from CDM programs up to and including 2018 in BHI's 2020 rate case (EB-2019-0023).

BHI disposed of lost revenues from 2011–2012 CDM programs in BHI's 2013 rate case, and its lost revenues from 2013-2015 in the 2016 application. It disposed of lost revenues from 2016 in its 2018 IRM application.

BHI included the impacts of CDM in the load forecast for BHI's 2014 cost of service rate case and estimated the CDM savings in 2014 (EB-2013-0115). The LRAMVA threshold estimated from 2014 CDM

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[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

[2] *Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2017 Rate Applications - Chapter 2 - Cost of Service*, Ontario Energy Board. July 14, 2017.

programs is compared to the calculated lost revenue from verified final CDM results. The difference between these two is the LRAMVA value BHI is claiming for both 2017 and 2018. This report determines the variance account balance for the following revenue losses:

- Lost revenues in 2017 related to programs offered in 2013,
- Lost revenues in 2017 related to programs offered in 2014,
- Lost revenues in 2017 related to programs offered in 2015,
- Lost revenues in 2017 related to programs offered in 2016,
- Lost revenues in 2017 related to programs offered in 2017,
- Lost revenues in 2018 related to programs offered in 2013,
- Lost revenues in 2018 related to programs offered in 2014,
- Lost revenues in 2018 related to programs offered in 2015,
- Lost revenues in 2018 related to programs offered in 2016,
- Lost revenues in 2018 related to programs offered in 2017, and
- Lost revenues in 2018 related to programs offered in 2018.

The carrying charges on the above variances through April 2020 are also reported.

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input assumptions currently available have been used to calculate the lost revenue values.

CDM RESULTS

The IESO performs evaluations of all of its programs, which examine gross energy savings from the programs, and the net-to-gross ratio (NTGR), and then from those calculates net energy savings for each initiative or program. Peak load reductions are also calculated and reported in the same way.

Provincial results are allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reports energy savings and peak demand reductions, by initiative or program in the current year, adjustments to the previous years based on updated validation, and contribution to total savings or reductions to the end of the 2011 to 2014 period and the 2015 to 2020 period. The savings and demand reductions for a particular year for most programs persist for a number of years. The savings and demand reductions for demand response programs do not persist beyond the year in which those particular savings and demand reductions occur. The IESO was requested to provide the persistence into future years of savings and reductions for each program in each year.

These are the best, most definitive, and defensible estimates of results associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes

The IESO reports results by program or initiative. These only partially map onto rate classes. Where customers in a program are from more than one rate classes, the LDC must consider project specific information for that program, and the rate classes of the customers undertaking the project.

Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. The allocation was calculated according to the billing unit of the relevant rate class. That is, for GS<50 projects, their allocation is the percentage of total kWh for projects in that rate class; for GS>50, their allocation is the percentage of total kW for projects in that rate class.

Application of reported results

For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported net demand reductions are used to calculate lost revenues related to CDM results.[3] The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[4]

The OEB has decided that lost revenue cannot be claimed from the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer used for billing purposes may not correspond with the demand response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month… Since the IESO's evaluations cannot confirm the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[5]

---

[3] The exception is streetlighting retrofit projects. Streetlighting is billed by kW, but streetlighting retrofit projects have no peak demand reductions associated with conservation measures. A special calculation is done for these, as described below.

[4] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2017-0182, May 19, 2017, p. 4.

[5] Ibid. p. 7.

Load reductions accounted for in the load forecast

In recent years, LDCs have incorporated projected load losses that will result from CDM programs in their load forecasts, submitted as part of their Cost of Service applications. When determining actual lost revenues, these forecasted reductions in a particular year need to be deducted from load losses attributable to CDM programs in that year to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception is for certain rate riders related to taxes, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

For most electricity distribution utilities in Ontario, including BHI, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported as first-year savings for programs by calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average rate is estimated based on the rate being four-twelfths of the previous year's rate (for January through April), and eight-twelfths of the current year's rate (for May through December).

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. Thus, 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the time of the results, until disposition.

REPORTING OF LOST REVENUE

The LDC reports these lost revenues on its financial statements in Account 1568, and the associated rate class-specific sub-accounts.

Results

Following the methodology described above, lost revenues were calculated for BHI. The results reference tables provided in the completed LRAMVA workform that uses the template provided by the OEB.

CDM RESULTS

IESO evaluation results

The most recent and appropriate final CDM evaluation reports from the IESO were used in support of the lost revenue calculations. The IESO provided final verified energy savings and demand reductions for 2011-2014 (including adjustments to saving estimates in 2011-2013), and final verified results for 2015-2017 (including adjustments to savings estimates in 2015-2016).

The April 2019 IESO Participation and Cost report was used to determine energy savings for 2018, and previously uncaptured and unverified adjustments for 2015-2017 programs. Demand reductions were estimated using the same kW/kWh ratio seen for verified results for the same program in that same year where available, or in previous years where there are not verified results for the same year. Demand reductions were not estimated for residential programs, which are billed by energy units.

The IESO provided BHI with persistence data for savings at the program level through 2017. For 2018, the IESO Participation and Cost report shows net energy savings in 2020 for 2015-2017 adjustments and 2018 data. Values for intermediary years were estimated by linear interpolation.

The data provided are presented in Tables 4c and 4d on Tab 4, and Tables 5a to 5d on Tab 5 of the LRAMVA work form.

Streetlighting projects

Starting in 2017, the City of Burlington undertook a series of projects under the Retrofit Program to retrofit streetlights to a more energy efficient light emitting diode (LED) technology.

Energy savings from these projects were reported within the Retrofit program results. Because streetlighting is not used during peak periods, the IESO normally reports zero peak demand savings from streetlighting projects. However, the streetlight retrofit projects do impact Burlington Hydro's revenues so a special calculation is done to calculate demand reductions of these projects and their impact on revenues, drawing on actual bill reductions.

The streetlighting retrofitting was implemented in stages and kW reductions were applied to the municipality's streetlighting account starting in October 2017 and continuing through 2018. Billed demand and calculated reductions are reported on Tab 8 of the OEB LRAMVA work form. Also shown on that tab, with the project details, is the quantity and types of fixtures changed.

In 2017, the result was a net reduction of 553 kW. The persistence from this project continues into future years, with net reductions of 3,863 kW yearly.

The 2018 the project resulted in a net reduction of 3,380 kW, which persists into future years with net reductions of 4,804 kW each year.

The actual lost revenue from the streetlighting retrofit project has been calculated directly by multiplying the reduction in the demand billed by the appropriate rate. A load profile is not needed and is not used to determine these reductions.

The streetlight upgrades that led to these savings represent incremental savings attributable to participation in the IESO program and do not include other savings that may have occurred outside of the IESO program. Burlington Hydro has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program.

As the streetlighting rate class is billed by kW, the calculated net kWh savings from the Retrofit LED upgrade projects do not impact Burlington Hydro's revenue. Thus, the energy savings have been manually removed from the 2017 and 2018 Retrofit program results each year.

Allocating results to rate classes

BHI provided information on the allocation of results to rate classes, drawing on project specific information provided by the IESO. In most cases, the allocation is straightforward as the program only impacts one rate class.

Initiatives that spanned multiple rate classes included Retrofit (and ERII), Small Business Lighting, and High Performance New Construction. Burlington Hydro estimated the allocation of projects to rate classes for each program based on the rate class of the customers implementing the project. For 2015, 2016 and 2017, IESO provided project specific net savings. For other years, Burlington Hydro estimated the allocation based on gross savings estimates from its project databases.

No allocation was provided for programs for which BHI has no program results.

BHI bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for BHI are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS>50 kW (kW)
- Unmetered Scattered Load (kWh)
- Streetlighting (kW)

Table 4c of the OEB LRAMVA work form shows the percentage allocation by rate class for 2013 results and adjustments. Table 4d of the OEB LRAMVA work form shows the percentage allocation by rate class for 2014 results. Tables 5-a, b, c, and d of the OEB LRAMVA work form shows the percentage allocation by rate class for 2015, 2016, 2017 and 2018 results respectively. In each year the rate class allocation percentage totals for each program may not add up to exactly 100% because the kW/kWh savings are not identical for all projects in a program and the allocation for the residential and GS<50 rate classes are the percentage of kWh savings in these classes, and for other rate classes it is the percentage of kW reductions in these rate classes.

Load reductions accounted for in the load forecast

The cost of service application affecting 2017 and 2018 results was filed for the 2014 rate year (EB-2013-0115). The load forecast associated with that application included a CDM adjustment to account for load losses from 2014 CDM programs. Table 2-a of the OEB LRAMVA work form shows the LRAMVA threshold that was estimated at the time of the load forecast, and that the OEB asked be used in the LRAMVA analysis during the 2019 IRM rate application.

Overall impact of CDM on load, by rate class

Multiplying the adjusted energy savings or demand reduction reported for BHI for each program by the allocation by rate class provides the impact on load of that CDM program within the appropriate rate class. The sum of the energy savings and demand reductions for all of the programs for each rate class provides the overall impact of CDM on load by rate class. The overall load impact for each calendar year includes the results for the CDM programs and any adjustments to the results in that year.

The bottom of Table 4c of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2013. The bottom of Table 4d of the work form shows the overall impact of CDM on load by rate class for 2014. The bottom of Tables 5-a, 5-b and 5-c, and 5-d of the OEB LRAMVA work form shows the overall impact of CDM on load by rate class for 2015, 2016, 2017 and 2018 respectively.

DISTRIBUTION RATES

The distribution rates that are used to calculate the CDM impact on distributor revenue for each rate class for BHI are shown in Table 3 of the OEB LRAMVA work form. The distribution rates are pro-rated from the rate year to the calendar year, as needed, using the number of months of each rate year in each calendar year. Table 3-a of the OEB LRAMVA work form shows the pro-rated rates used for 2017 and 2018. 2011-2016 rates were removed, as lost revenues through 2016 were claimed in the 2019 IRM application (EB-2018-0021).

LOST REVENUES

The lost revenues for each year by rate class for BHI calculated from final CDM program results are shown in Table 1 of the OEB LRAMVA work form. The lost revenue for 2017 and 2018 is based on the load impact for each rate class in 2017-2018 multiplied by the rate for that rate class in that year. The load impact includes the impact of CDM programs in 2017-2018 and the persistence of the CDM program impact from programs offered in 2013 through 2017 in 2018.

Table 1 of the OEB LRAMVA work form also shows the lost revenue in 2017 and 2018 due to CDM activities accounted for in BHI's 2014 load forecast. The impact on BHI's revenue is the variance between what is calculated from final CDM program results and CDM results already accounted for in the load forecast.

CARRYING CHARGES

The monthly carrying charges by rate class on BHI's lost revenue variance are shown in Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues resulted (January 2017), through to April 30, 2020.

Conclusions

The LRAMVA balance at the end of December 2018 for BHI that includes results from 2013 – 2018 CDM programs and adjustments to 2013 to 2017 results is $1,127,219. The total carrying charges on this LRAMVA balance accumulated to April 30, 2019 are $52,781. These balances are attributable to individual rate classes according to the following table:

Rate class	Principal ($)	Carrying charges ($)	LRAMVA total ($)
Residential	$457,872	$22,311	$480,183
GS < 50 kW	$249,330	$11,284	$260,614
GS > 50 kW	$387,163	$17,889	$405,051
Unmetered Scattered Load	-$1,173	-$55	-$1,228
Streetlighting	$34,028	$1,352	$35,380
Total	**$1,127,219**	**$52,781**	**$1,180,000**

NOTE: There are no LRAMVA or carrying charge values associated with rate classes not included in this table.

Where negative values are shown, that indicates the actual reduction in load from CDM programs was less than the LRAMVA amount associated with the load forecast.

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Appendix H – ICM Module

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Note: Depending on the selections made below, certain worksheets in this workbook will be hidden.

Version 5.00

Utility Name	Burlington Hydro Inc.
Assigned EB Number	EB-2019-0023
Name of Contact and Title	Sally Blackwell, Vice President, Regulatory Compliance and Asset Management
Phone Number	905-336-4373
Email Address	sblackwell@burlingtonhydro.com

Is this Capital Module being filed in a CoS or Price-Cap IR Application?	Price-Cap IR	Rate Year	2020
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Burlington Hydro Inc. is applying:	6	Next OEB Scheduled Rebasing Year	2021
Burlington Hydro Inc. is applying for:	ICM Approval		
Last Rebasing Year:	2014		
The most recent complete year for which actual billing and load data exists	2018		
Current IPI	1.50%		
Strech Factor Assigned to Middle Cohort*	III		
Stretch Factor Value	0.30%		
Price Cap Index	1.20%		

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2018 Actual Distribution Demand}}{\text{Revenues Based on 2014 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

**As per ACM/ICM policy, the middle cohort stretch factor is applied to all ACM/ICM applications.*

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Burlington Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **5**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 4,999 KW
4	UNMETERED SCATTERED LOAD
5	STREET LIGHTING

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Burlington Hydro Inc.

Input the billing determinants associated with Burlington Hydro Inc.'s Revenues Based on 2018 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

Rate Class	Units	2018 Actual Distribution Demand: Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Current Approved Distribution Rates: Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW
RESIDENTIAL	$/kWh	61,252	535,270,676		26.03	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	5,703	173,151,275		26.57	0.0142	0.0000
GENERAL SERVICE 50 TO 4,999 KW	$/kW	985		2,378,408	62.29	0.0000	3.0664
UNMETERED SCATTERED LOAD	$/kWh	579	3,138,760		9.55	0.0166	0.0000
STREET LIGHTING	$/kW	15,400		20,571	0.64	0.0000	4.6183

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Calculation of pro forma 2014 Revenues. No input required.

Rate Class	2018 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	K = G / J	L = H / J	M = I / J	N
RESIDENTIAL	61,252	535,270,676		26.03	0.0000	0.0000	19,132,675	0	0	19,132,675	100.0%	0.0%	0.0%	60.2%
GENERAL SERVICE LESS THAN 50 kW	5,703	173,151,275		26.57	0.0142	0.0000	1,818,345	2,458,748	0	4,277,093	42.5%	57.5%	0.0%	13.5%
GENERAL SERVICE 50 TO 4,999 KW	985		2,378,408	62.29	0.0000	3.0664	736,268	0	7,293,150	8,029,418	9.2%	0.0%	90.8%	25.3%
UNMETERED SCATTERED LOAD	579	3,138,760		9.55	0.0166	0.0000	66,353	52,103	0	118,457	56.0%	44.0%	0.0%	0.4%
STREET LIGHTING	15,400		20,571	0.64	0.0000	4.6183	118,272	0	95,003	213,275	55.5%	0.0%	44.5%	0.7%
Total	**83,919**	**711,560,711**	**2,398,979**				**21,871,912**	**2,510,852**	**7,388,153**	**31,770,917**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Applicants Rate Base

Last COS Rebasing: 2014

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	242,255,337	A			
Add: CWIP Re-based Opening	$	-	B			
Re-based Capital Additions	$	7,730,045	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	$	-	F			
Gross Fixed Assets - Re-based Closing	$	249,985,382	G			
Average Gross Fixed Assets				$	246,120,360	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	139,112,890	I			
Re-based Depreciation Expense	$	4,510,060	J			
Re-based Disposals	$	-	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	143,622,950	M			
Average Accumulated Depreciation				$	141,367,920	N = (I + M) / 2
Average Net Fixed Assets				**$**	**104,752,440**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	208,278,793	P			
Working Capital Allowance Rate		13.0%	Q			
Working Capital Allowance				**$**	**27,076,243**	R = P * Q
Rate Base				**$**	**131,828,683**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	5,273,147	W = S * T
Deemed Long Term Debt %		56.00%	U	$	73,824,062	X = S * U
Deemed Equity %		40.00%	V	$	52,731,473	Y = S * V
Short Term Interest		2.11%	Z	$	111,263	AC = W * Z
Long Term Interest		4.73%	AA	$	3,491,878	AD = X * AA
Return on Equity		9.36%	AB	$	4,935,666	AE = Y * AB
Return on Rate Base				**$**	**8,538,807**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	17,576,533	AG			
Amortization	$	4,510,060	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	211,146	AJ			
Low Voltage	$	-	AK			
Transformer Allowance	$	571,049	AL			
			AM			
			AN			
			AO			
				$	**22,868,788**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	817,981	AQ			
Late Payment Charges	-$	241,000	AR			
Other Distribution Income	-$	625,033	AS			
Other Income and Deductions	-$	317,000	AT	**-$**	**2,001,014**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**29,406,581**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 4)				$	31,770,917	AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Input the billing determinants associated with Burlington Hydro Inc.'s Revenues Based on 2014 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

Rate Class	2014 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$K = G / J_{total}$	$L = H / J_{total}$	$M = I / J_{total}$	N
RESIDENTIAL	59,869	553,858,289		26.03	0.0000	0.0000	18,700,681	0	0	18,700,681	59.4%	0.0%	0.0%	59.4%
GENERAL SERVICE LESS THAN 50 kW	5,224	173,842,956		26.57	0.0142	0.0000	1,665,620	2,468,570	0	4,134,190	5.3%	7.8%	0.0%	13.1%
GENERAL SERVICE 50 TO 4,999 KW	1,012		2,451,173	62.29	0.0000	3.0664	756,450	0	7,516,277	8,272,727	2.4%	0.0%	23.9%	26.3%
UNMETERED SCATTERED LOAD	605	3,151,827		9.55	0.0166	0.0000	69,333	52,320	0	121,653	0.2%	0.2%	0.0%	0.4%
STREET LIGHTING	15,272		30,525	0.64	0.0000	4.6183	117,289	0	140,974	258,263	0.4%	0.0%	0.4%	0.8%
Total	**81,982**	**730,853,072**	**2,481,698**				**21,309,373**	**2,520,890**	**7,657,250**	**31,487,514**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

	Current OEB-Approved Base Rates			2018 Actual Distribution Demand										
Rate Class	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
	A	B	C	D	E	F	G	H	I	J	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	O
RESIDENTIAL	26.03	0	0	61,252	535,270,676	0	19,132,675	0	0	19,132,675	60.22%	0.00%	0.00%	60.2%
GENERAL SERVICE LESS THAN 50 kW	26.57	0.0142	0	5,703	173,151,275	0	1,818,345	2,458,748	0	4,277,093	5.72%	7.74%	0.00%	13.5%
GENERAL SERVICE 50 TO 4,999 KW	62.29	0	3.0664	985	0	2,378,408	736,268	0	7,293,150	8,029,418	2.32%	0.00%	22.96%	25.3%
UNMETERED SCATTERED LOAD	9.55	0.0166	0	579	3,138,760	0	66,353	52,103	0	118,457	0.21%	0.16%	0.00%	0.4%
STREET LIGHTING	0.64	0	4.6183	15,400	0	20,571	118,272	0	95,003	213,275	0.37%	0.00%	0.30%	0.7%
Total							**21,871,912**	**2,510,852**	**7,388,153**	**31,770,917**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times ((1+g) \times (1+PCI))^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2014**	
Price Cap IR Year in which Application is made		**6**	n
Price Cap Index		**1.20%**	PCI
Growth Factor Calculation			
Revenues Based on 2018 Actual Distribution Demand		**$31,770,917**	
Revenues Based on 2014 Board-Approved Distribution Demand		**$31,487,514**	
Growth Factor		**0.23%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	242,255,337	
Add: CWIP Opening	$	-	
Capital Additions	$	7,730,045	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	$	-	
Gross Fixed Assets - Closing	$	249,985,382	
Average Gross Fixed Assets	$	246,120,360	
Accumulated Depreciation - Opening	$	139,112,890	
Depreciation Expense	$	4,510,060	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	143,622,950	
Average Accumulated Depreciation	$	141,367,920	
Average Net Fixed Assets	$	104,752,440	
Working Capital Allowance			
Working Capital Allowance Base	$	208,278,793	
Working Capital Allowance Rate		13%	
Working Capital Allowance	$	27,076,243	
Rate Base	**$**	**131,828,683**	RB
Depreciation	**$**	**4,510,060**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2015	**152%**
Price Cap IR Year 2016	**152%**
Price Cap IR Year 2017	**153%**
Price Cap IR Year 2018	**154%**
Price Cap IR Year 2019	**154%**
Price Cap IR Year 2020	**155%**
Price Cap IR Year 2021	**155%**
Price Cap IR Year 2022	**156%**
Price Cap IR Year 2023	**157%**
Price Cap IR Year 2024	**157%**

Threshold CAPEX — $Threshold\ Value \times d$

Price Cap IR Year 2015	**$**	**6,843,201**
Price Cap IR Year 2016	**$**	**6,870,073**
Price Cap IR Year 2017	**$**	**6,897,328**
Price Cap IR Year 2018	**$**	**6,924,972**
Price Cap IR Year 2019	**$**	**6,953,011**
Price Cap IR Year 2020	**$**	**6,981,450**
Price Cap IR Year 2021	**$**	**7,010,296**
Price Cap IR Year 2022	**$**	**7,039,553**
Price Cap IR Year 2023	**$**	**7,069,228**
Price Cap IR Year 2024	**$**	**7,099,326**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Identify ALL Proposed ACM and ICM projects and related CAPEX costs in the relevant years

	Cost of Service Test Year 2014	*Price Cap IR* Year 1 2015	*Price Cap IR* Year 2 2016	*Price Cap IR* Year 3 2017	*Price Cap IR* Year 4 2018
CAPEX[1]					
Materiality Threshold		$ 6,843,201	$ 6,870,073	$ 6,897,328	$ 6,924,972
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)		$ -	$ -	$ -	$ -

Project Descriptions:	Type	Test Year 2014	Year 1 2015 Proposed ACM/ICM	Year 1 2015 Amortization Expense	Year 1 2015 CCA	Year 2 2016 Proposed ACM/ICM	Year 2 2016 Amortization Expense	Year 2 2016 CCA	Year 3 2017 Proposed ACM/ICM	Year 3 2017 Amortization Expense	Year 3 2017 CCA	Year 4 2018 Proposed ACM/ICM	Year 4 2018 Amortization Expense	Year 4 2018 CCA
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maximum Allowed Incremental Capital			$ -			$ -			$ -			$ -		

	Price Cap IR (Deferred Rebasing) (if necessary) *Price Cap IR* Year 5 2019	*Price Cap IR (Deferred Rebasing) (if necessary)* *Price Cap IR* Year 6 2020
Distribution System Plan CAPEX		$ 11,765,000
Materiality Threshold	$ 6,953,011	$ 6,981,450
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 4,783,550

Project Descriptions:	Type		Year 5 2019 Proposed ACM/ICM	Year 5 2019 Amortization Expense	Year 5 2019 CCA	Year 6 2020 Proposed ACM/ICM	Year 6 2020 Amortization Expense	Year 6 2020 CCA
Project 1: CIS	**New ICM**					$ 1,445,000	$ 289,000	$ 794,750
Project 2: GIS	**New ICM**					$ 500,000	$ 100,000	$ 275,000
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ 1,945,000	$ 389,000	$ 1,069,750
Maximum Allowed Incremental Capital			$ -			$ 1,945,000		

1. For the Cost of Service Test Year, CAPEX refers to the CAPEX approved in the DSP. For subsequent Price CAP IR years, the CAPEX to be entered is the actual CAPEX. For the current Price Cap IR year, the CAPEX to be entered is the proposed CAPEX including any ICM/updated ACM project CAPEX for the year.

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Incremental Capital Adjustment **Rate Year:** **2020**

Current Revenue Requirement

Current Revenue Requirement - Total	$	29,406,581	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Half Year* Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 1,945,000	$ 972,500	B
Depreciation Expense	$ 389,000	$ 194,500	C
CCA	$ 1,069,750	$ 534,875	V

The half year rule is applied as the distributor is scheduled to rebase in the next rate year.

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	972,500	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	194,500	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	875,250	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	35,010	G = D * E
Deemed Long-Term Debt	56.0%	F	$	490,140	H = D * F
	Rate (%)				
Short-Term Interest	2.11%	I	$	739	K = G * I
Long-Term Interest	4.73%	J	$	23,184	L = H * J
Return on Rate Base - Interest			$	23,922	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	350,100	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.36%	O	$	32,769	Q = P * O
Return on Rate Base - Total			$	56,692	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	194,500	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	32,769	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	194,500	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	534,875	V
Incremental Taxable Income			-$	307,606	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	81,515	Y = W * X
Grossed-Up Taxes/PILs			-$	110,905	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	56,692	AA
Amortization Expense - Total	S	$	194,500	AB
Grossed-Up Taxes/PILs	Z	-$	110,905	AC
Incremental Revenue Requirement		$	140,286	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Burlington Hydro Inc.

Calculation of incremental rate rider. Choose one of the 3 options: Fixed and Variable Rate Riders

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 7	*From Sheet 7*	*From Sheet 7*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	60.22%	0.00%	0.00%	84,481	0	0	84,481	61,252	535,270,676		0.11	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.72%	7.74%	0.00%	8,029	10,857	0	18,886	5,703	173,151,275		0.12	0.0001	0.0000
GENERAL SERVICE 50 TO 4,999 KW	2.32%	0.00%	22.96%	3,251	0	32,203	35,454	985		2,378,408	0.28	0.0000	0.0135
UNMETERED SCATTERED LOAD	0.21%	0.16%	0.00%	293	230	0	523	579	3,138,760		0.04	0.0001	0.0000
STREET LIGHTING	0.37%	0.00%	0.30%	522	0	419	942	15,400		20,571	0.00	0.0000	0.0204
Total	**68.84%**	**7.90%**	**23.25%**	**96,577**	**11,087**	**32,623**	**140,286**	**83,919**	**711,560,711**	**2,398,979**			
							140,286						
							From Sheet 11, E93						

Note: As per the OEB's letter issued July 16, 2015 (EB-2012-0410), Reside

Appendix I – Project Summary - Customer Information System

PROJECT SUMMARY (APPENDIX I)

Project #	#1
Project Name	Customer Information System Replacement
Project Category	General Plant
Project Duration	2 years
Budget Amount	$1,445,000
Expected In-Service Date	2020

Project Description and Drivers:

Burlington Hydro's ("BHI's") Customer Information System (CIS) (including an integrated Customer Portal) is a key enabler of customer service and billing capabilities. This strategic asset collects and stores customer account information and is the system of reference for providing prompt reply to customer inquiries. It supports the integrated delivery of customer care and revenue cycle processes, including meter data management, producing customers' bills and collecting revenues.

BHI's initiative to replace its current CIS is based on the following drivers:

- Technological obsolescence of the current system, which does not meet the needs of current Advanced Metering Infrastructure ("AMI") based billing processes (i.e. it is not predicated on time-of-use rates)
- Vendor no longer provides full CIS upgrades in the Ontario market
- Modifications required to be made to the current system in response to new public policy initiatives and regulatory changes are challenging, costly and time consuming
- High cost of ownership under the current CIS system, as the maintenance pricing model increases each year based on accumulated modifications
- Ability to meet customer demand for new functionality (e.g. enhanced customer notifications, integrated online customer portal)

BHI currently operates the Daffron CIS solution. This solution is 24 years old, was originally acquired and implemented in 1994-1995 and was based on mature technology at the time of purchase. BHI's Daffron CIS has been heavily customized to meet the needs of the regulated Ontario electricity market, however, Daffron no longer provides full CIS upgrades in the Ontario market. Operating under the current CIS, BHI expects to incur additional expenses and lost business operations efficiency as costly and challenging modifications are required in response to public policy and regulatory changes. Further, BHI's customers have expressed their dissatisfaction and frustration with its current system and have been asking for more functionality for many years.

Benefits of a new CIS are as follows:

- Modern technology specifically designed to meet the needs of current Advanced Metering Infrastructure ("AMI") based billing processes in Ontario
- Better features and functionality to support improved Customer service levels (streamlined and automated billing-related routines, faster processing of field-based customer service orders)
- Configurable functionality will reduce the cost and complexity of modifications, and facilitate faster response to new public policy initiatives and regulatory changes
- Meet customer demand for new products and services (e.g. integrated and consolidated customer web portal with account balances, payments, e-Bills, consumption, TOU toolkit, transaction history, timely notification with ability to

Project #	#1
Project Name	Customer Information System Replacement
Project Category	General Plant
Project Duration	2 years
Budget Amount	$1,445,000
Expected In-Service Date	2020

consolidate multiple accounts)
- Integration with web based, self-serve Customer Service options (e.g. 'Move In/Move Out', Stop/Start Service, Forms on a Smart Phone App)
- Deploy 'Chat' Technology
- Provide a platform for future capability such as Customer Relationship Management including sales, marketing, segmentation, sales force automation (SFA) and risk/profitability analysis
- Provide a foundation for enterprise wide integration of other modules (e.g. Financials, Work Order Management, Inventory Control & Warehouse Management)

BHI has considered several options, including:
1. Upgrading the current Daffron CIS System.
2. Replacement with a new Tier 2 CIS System.
3. Replacement with a new Tier 1 CIS in a shared services model with other LDCs.

An analysis of these options is outlined below. BHI has proceeded with sourcing and operating a new Tier 2 CIS solution.

Options Considered:

1. **Upgrading the Current Daffron CIS**:
BHI considered the option to 'upgrade' its current CIS which would be the lowest cost option initially. However, the current CIS is an aging legacy system which is heavily customized, and the vendor no longer provides full CIS upgrades in the Ontario market. It remains an old technology and design solution that does not meet the needs of the current AMI based billing processes and their related Meter Management requirements. It continues to be difficult and costly to change. Operating under the current CIS, BHI expects to incur additional expenses and lost business operations efficiency as costly and challenging modifications are required in response to public policy and regulatory changes.

2. **Replacement with a new Tier 2 CIS**
BHI explored less expensive (Tier 2) solutions that met its functional, technical and financial needs at a significantly less cost than a comparable Tier 1 solution. BHI proceeded forward with their Tier 2 Vendor of choice and completed the acquisition of its new Ontario regulatory compliant CIS in 2019. BHI is successfully proceeding through the implementation ofits new CIS with a cutover scheduled for 2020. BHI estimates that this project will cost approximately $1.445M incurred through 2019 and 2020.

3. **Replacement with a new Tier 1 CIS**
In 2016 and 2017, BHI and two other Ontario LDCs explored a joint CIS implementation strategy and developed common requirements. Most of the solutions proposed were

Project #	#1
Project Name	Customer Information System Replacement
Project Category	General Plant
Project Duration	2 years
Budget Amount	$1,445,000
Expected In-Service Date	2020

not suitable to meet the consortium's joint needs. Although the Two Tier 1 solutions appeared to meet BHI's functional needs, they were complex to implement and operate, and neither solution was the most cost effective option for BHI and its customers.

Prudence: BHI considered several options to upgrade its CIS. Continuing to use Daffron would require ongoing upgrades and modifications in order to meet the needs of current Advanced Metering Infrastructure ("AMI") based billing processes and future public policy and regulatory changes. These modifications are challenging, costly, and time consuming to implement. BHI considered several options to replace its CIS including two Tier 1 solutions. These would have been complex to implement and operate, and neither solution was the most cost effective option for BHI and its customers. BHI has proceeded to replace its CIS with a highly functional Tier 2 solution in 2019. The selected option meets the existing and future requirements for an Ontario-based, advanced technology CIS, and offers full functionality in Customer Service, Billing, Meter Data Management, Collections, Inventory and Financial Receivables. It also represents a more cost effective option for BHI and its customers compared to the Tier 1 alternatives.

Appendix J – Project Summary - Geographic Information System

PROJECT SUMMARY (APPENDIX J)

Project #	#2
Project Name	Geographic Information System Replacement
Project Category	General Plant
Project Duration	1 year(s)
Budget Amount	$ 500,000
Expected In-Service Date	2020

Project Description and Drivers:

Burlington Hydro Inc.’s (BHI) Geographic Information System (GIS) is the central repository for all distribution asset information and is used by several departments across the organization. The GIS is the source database for several processes including Asset Data Collection and Asset Management, and feeds information directly to BHI’s Outage Management System.

BHI’s initiative to obtain a new GIS is driven by the software incompatibility and obsolescence of the current GIS, and by opportunities to improve business processes through new system functionality.

BHI currently operates a SpatialNET Power GIS, which is only compatible with Microsoft Windows 7. The three primary drivers behind BHI’s decision to replace its GIS are:

1) Microsoft support for Windows 7 ends on January 14, 2020. The GIS vendor will not update the software to be compatible with newer versions of Windows.
2) The GIS vendor no longer provides bug fixes, enhancements, or updates (since BHI is the only electric utility in North America that uses SpatialNET).
3) Compatibility issues are impacting operational efficiency. For example, engineering drawings sent to BHI from consultants are not backwards compatible with the out of date format that SpatialNET uses. This results in additional time spent converting drawings, which occasionally results in data loss.

In addition to addressing the issues identified above, the benefits of a new GIS are as follows:

- Improved decision making from new functionality (ability to trace upstream / downstream assets, validating connectivity)
- Improved operability (faster refresh rate on queries, ability to update feature attributes in bulk, ability to generate larger geographic areas at once)
- Streamlined data validation (drop down menu’s, mandatory attributes)
- Provides a platform for future integration points with software products currently in use at BHI (Engineering Analysis, Engineering Standards, ERP)
- Tracks historical records for Asset Management purposes
- Regular software releases and bug fixes

BHI’s current GIS is a barrier to making timely changes and enhancements in the future. A modern, robust GIS will allow BHI to:

- Accommodate current and future electrical feature classes (e.g. distributed generation, intelligent grid equipment, etc.)
- Introduce new products and services (e.g. transformer loading, web-based GIS viewer with sub-second refresh rate)
- Meet changing and increasing customer and/ or business needs in a timely manner
- Continue to comply with OEB regulations

PROJECT SUMMARY (APPENDIX J)

Project #	#2
Project Name	Geographic Information System Replacement
Project Category	General Plant
Project Duration	1 year(s)
Budget Amount	$ 500,000
Expected In-Service Date	2020

BHI has considered three options; 1) Status Quo, 2) Vendor A, and 3) Vendor B.

Options Considered:

1) Status Quo: Continuing ‘Status Quo’ with the current GIS was not an option because operating a critical system on a platform no longer supported by Microsoft poses a significant cyber security risk to the organization (security and software updates from Microsoft are no longer available). Operational efficiency is also at risk as software updates and support for bug fixes for the current GIS are no longer available.
2) Vendor A: Vendor A continually updates their software product to run on the latest version of Windows and Windows security patches (released monthly). Vendor A also has a strong electric utility presence (not only in Southern Ontario, but around the world), and releases software upgrades on a yearly basis and bug fixes on a quarterly basis. The new GIS is out of the box with minimal customization allowing for low cost, minimal impact future upgrades. It provides opportunities to improve business processes through new system functionality. Vendor A also represents the lowest cost, highest functionality, least proprietary solution that is most easily integrated within BHI’s existing IT environment, and avoids future risk in the shifting GIS marketplace.
3) Vendor B: Vendor B provides similar upgrade services as Vendor A and also provides opportunities to improve business processes through new system functionality. However, it uses proprietary technology with limited flexibility for BHI to modify. It is also more expensive than Vendor A, and it is expected there will be a forced upgrade in the next few years at additional cost to BHI.

Prudence: BHI has operated SpatialNET GIS as long as possible with minimal vendor support, bug fixes and no functionality enhancements. Due to the impending Windows 7 support cutoff and the cyber security risk it poses to BHI and its customers, status quo is no longer an option. Vendor A addresses the software issues with the current GIS, and provides opportunities to improve business processes through new system functionality. BHI has demonstrated prudence by selecting the vendor with the lowest cost, highest functionality, and least proprietary solution that is most easily integrated within the existing IT environment.

Appendix K – Bill Impacts

Ontario Energy Board

Incentive Rate-setting Mechanism Rate Generator for 2020 Filers

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 750 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. Include bill comparisons for Non-RPP (retailer) as well. **To assess the combined effects of the shift to fixed rates and other bill impacts associated with changes in the cost of distribution service, applicants are to include a total bill impact for a residential customer at the distributor's 10th consumption percentile (In other words, 10% of a distributor's residential customers consume at or less than this level of consumption on a monthly basis). Refer to section 3.2.3 of the Chapter 3 Filing Requirements For Electricity Distribution Rate Applications.**

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note:
1. For those classes that are not eligible for the RPP price, the weighted average price including Class B GA through end of May 2018 of $0.1117/kWh (IESO's Monthly Market Report for May 2018, page 22) has been used to represent the cost of power. For those classes on a retailer contract, applicants should enter the contract price (plus GA) for a more accurate estimate. Changes to the cost of power can be made directly on the bill impact table for the specific class.
2. Please enter the applicable billing determinant (e.g. number of connections or devices) to be applied to the monthly service charge for unmetered rate classes in column N. If the monthly service charge is applied on a per customer basis, enter the number "1". Distributors should provide the number of connections or devices reflective of a typical customer in each class.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

RATE CLASSES / CATEGORIES ***(eg: Residential TOU, Residential Retailer)***	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**Current Loss Factor (eg: 1.0351)**	**Proposed Loss Factor**	**Consumption (kWh)**	**Demand kW (if applicable)**	**RTSR Demand or Demand-Interval?**	**Billing Determinant Applied to Fixed Charge for Unmetered Classes (e.g. # of devices/connections).**
RESIDENTIAL SERVICE CLASSIFICATION	kWh	RPP	1.0373	1.0373	700			
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	RPP	1.0373	1.0373	1,500			
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0373	1.0373	36,700	200	DEMAND - INTERVAL	
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	RPP	1.0373	1.0373	2,000			1
STREET LIGHTING SERVICE CLASSIFICATION	kW	Non-RPP (Other)	1.0373	1.0373	175	0	DEMAND	1
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				
Add additional scenarios if required			1.0373	1.0373				

Table 2

RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kWh	$ 0.80	3.0%	$ (0.10)	-0.3%	$ 0.55	1.4%	$ 0.58	0.6%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kWh	$ 2.20	4.5%	$ 0.35	0.6%	$ 1.75	2.3%	$ 1.84	0.9%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 31.55	4.5%	$ 21.26	3.0%	$ 92.62	5.2%	$ 104.66	1.5%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kWh	$ 0.54	1.3%	$ (1.24)	-2.5%	$ 0.63	0.8%	$ 0.71	0.3%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kW	$ 0.41	24.4%	$ 0.58	24.1%	$ 0.64	19.6%	$ 0.72	2.7%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	700 kWh
Demand	- kW
Current Loss Factor	1.0373
Proposed/Approved Loss Factor	1.0373

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 26.03	1	$ 26.03	$ 26.30	1	$ 26.30	$ 0.27	1.04%	
Distribution Volumetric Rate	$ -	700	$ -	$ -	700	$ -	$ -		
Fixed Rate Riders	$ 0.34	1	$ 0.34	$ 0.45	1	$ 0.45	$ 0.11	32.35%	
Volumetric Rate Riders	$ 0.0003	700	$ 0.21	$ 0.0009	700	$ 0.63	$ 0.42	200.00%	
Sub-Total A (excluding pass through)			**$ 26.58**			**$ 27.38**	**$ 0.80**	**3.01%**	
Line Losses on Cost of Power	$ 0.0824	26	$ 2.15	$ 0.0824	26	$ 2.15	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	700	$ -	-$ 0.0008	700	$ (0.56)	$ (0.56)		
CBR Class B Rate Riders	$ -	700	$ -	-$ 0.0001	700	$ (0.07)	$ (0.07)		
GA Rate Riders	$ -	700	$ -	$ -	700	$ -	$ -		
Low Voltage Service Charge	$ -	700	$ -		700	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ 0.27	1	$ 0.27	$ -	1	$ -	$ (0.27)	-100.00%	
Additional Volumetric Rate Riders		700	$ -	$ -	700	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.57**			**$ 29.47**	**$ (0.10)**	**-0.34%**	
RTSR - Network	$ 0.0071	726	$ 5.16	$ 0.0076	726	$ 5.52	$ 0.36	7.04%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0064	726	$ 4.65	$ 0.0068	726	$ 4.94	$ 0.29	6.25%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 39.37**			**$ 39.93**	**$ 0.55**	**1.41%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	726	$ 2.47	$ 0.0034	726	$ 2.47	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	726	$ 0.36	$ 0.0005	726	$ 0.36	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0650	455	$ 29.58	$ 0.0650	455	$ 29.58	$ -	0.00%	
TOU - Mid Peak	$ 0.0940	119	$ 11.19	$ 0.0940	119	$ 11.19	$ -	0.00%	
TOU - On Peak	$ 0.1340	126	$ 16.88	$ 0.1340	126	$ 16.88	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 100.10**			**$ 100.65**	**$ 0.55**	**0.55%**	
HST	13%		$ 13.01	13%		$ 13.08	$ 0.07	0.55%	
8% Rebate	8%		$ (8.01)	8%		$ (8.05)	$ (0.04)		
Total Bill on TOU			**$ 105.10**			**$ 105.69**	**$ 0.58**	**0.55%**	

Customer Class: GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP: RPP
Consumption 1,500 kWh
Demand - kW
Current Loss Factor 1.0373
Proposed/Approved Loss Factor 1.0373

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 26.57	1	$ 26.57	$ 26.85	1	$ 26.85	$ 0.28	1.05%	
Distribution Volumetric Rate	$ 0.0142	1500	$ 21.30	$ 0.0143	1500	$ 21.45	$ 0.15	0.70%	
Fixed Rate Riders	$ 0.36	1	$ 0.36	$ 0.48	1	$ 0.48	$ 0.12	33.33%	
Volumetric Rate Riders	$ 0.0007	1500	$ 1.05	$ 0.0018	1500	$ 2.70	$ 1.65	157.14%	
Sub-Total A (excluding pass through)			**$ 49.28**			**$ 51.48**	**$ 2.20**	**4.46%**	
Line Losses on Cost of Power	$ 0.0824	56	$ 4.61	$ 0.0824	56	$ 4.61	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	1,500	$ -	-$ 0.0007	1,500	$ (1.05)	$ (1.05)		
CBR Class B Rate Riders	$ -	1,500	$ -	-$ 0.0001	1,500	$ (0.15)	$ (0.15)		
GA Rate Riders	$ -	1,500	$ -	$ -	1,500	$ -	$ -		
Low Voltage Service Charge	$ -	1,500	$ -		1,500	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%	
Additional Fixed Rate Riders	$ 0.65	1	$ 0.65	$ -	1	$ -	$ (0.65)	-100.00%	
Additional Volumetric Rate Riders		1,500	$ -	$ -	1,500	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 55.11**			**$ 55.46**	**$ 0.35**	**0.64%**	
RTSR - Network	$ 0.0068	1,556	$ 10.58	$ 0.0073	1,556	$ 11.36	$ 0.78	7.35%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	1,556	$ 8.87	$ 0.0061	1,556	$ 9.49	$ 0.62	7.02%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 74.56**			**$ 76.31**	**$ 1.75**	**2.35%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	1,556	$ 5.29	$ 0.0034	1,556	$ 5.29	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	1,556	$ 0.78	$ 0.0005	1,556	$ 0.78	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0650	975	$ 63.38	$ 0.0650	975	$ 63.38	$ -	0.00%	
TOU - Mid Peak	$ 0.0940	255	$ 23.97	$ 0.0940	255	$ 23.97	$ -	0.00%	
TOU - On Peak	$ 0.1340	270	$ 36.18	$ 0.1340	270	$ 36.18	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 204.40**			**$ 206.15**	**$ 1.75**	**0.86%**	
HST	13%		$ 26.57	13%		$ 26.80	$ 0.23	0.86%	
8% Rebate	8%		$ (16.35)	8%		$ (16.49)	$ (0.14)		
Total Bill on TOU			**$ 214.62**			**$ 216.46**	**$ 1.84**	**0.86%**	

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	**36,700** kWh
Demand	**200** kW
Current Loss Factor	**1.0373**
Proposed/Approved Loss Factor	**1.0373**

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 62.29	1	$ 62.29	$ 62.94	1	$ 62.94	$ 0.65	1.04%	
Distribution Volumetric Rate	$ 3.0664	200	$ 613.28	$ 3.0986	200	$ 619.72	$ 6.44	1.05%	
Fixed Rate Riders	$ 0.83	1	$ 0.83	$ 1.11	1	$ 1.11	$ 0.28	33.73%	
Volumetric Rate Riders	$ 0.1040	200	$ 20.80	$ 0.2249	200	$ 44.98	$ 24.18	116.25%	
Sub-Total A (excluding pass through)			**$ 697.20**			**$ 728.75**	**$ 31.55**	**4.53%**	
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -		
Total Deferral/Variance Account Rate Riders	$ -	200	$ -	-$ 0.2452	200	$ (49.04)	$ (49.04)		
CBR Class B Rate Riders	$ -	200	$ -	-$ 0.0300	200	$ (6.00)	$ (6.00)		
GA Rate Riders	$ -	36,700	$ -	$ 0.0014	36,700	$ 51.38	$ 51.38		
Low Voltage Service Charge	$ -	200	$ -		200	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 6.63	1	$ 6.63	$ -	1	$ -	$ (6.63)	-100.00%	
Additional Volumetric Rate Riders		200	$ -	$ -	200	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 703.83**			**$ 725.09**	**$ 21.26**	**3.02%**	
RTSR - Network	$ 2.8046	200	$ 560.92	$ 2.9906	200	$ 598.12	$ 37.20	6.63%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 2.4996	200	$ 499.92	$ 2.6704	200	$ 534.08	$ 34.16	6.83%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,764.67**			**$ 1,857.29**	**$ 92.62**	**5.25%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	38,069	$ 129.43	$ 0.0034	38,069	$ 129.43	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	38,069	$ 19.03	$ 0.0005	38,069	$ 19.03	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1101	38,069	$ 4,191.39	$ 0.1101	38,069	$ 4,191.39	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 6,104.78**			**$ 6,197.40**	**$ 92.62**	**1.52%**	
HST	13%		$ 793.62	13%		$ 805.66	$ 12.04	1.52%	
Total Bill on Average IESO Wholesale Market Price			**$ 6,898.40**			**$ 7,003.06**	**$ 104.66**	**1.52%**	

Customer Class:	**UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**2,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0373**
Proposed/Approved Loss Factor	**1.0373**

	Current OEB-Approved			**Proposed**			**Impact**		
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**	
Monthly Service Charge	$ 9.55	1	$ 9.55	$ 9.65	1	$ 9.65	$ 0.10	1.05%	
Distribution Volumetric Rate	$ 0.0166	2000	$ 33.20	$ 0.0168	2000	$ 33.60	$ 0.40	1.20%	
Fixed Rate Riders	$ 0.13	1	$ 0.13	$ 0.17	1	$ 0.17	$ 0.04	30.77%	
Volumetric Rate Riders	-$ 0.0001	2000	$ (0.20)	-$ 0.0001	2000	$ (0.20)	$ -	0.00%	
Sub-Total A (excluding pass through)			**$ 42.68**			**$ 43.22**	**$ 0.54**	**1.27%**	
Line Losses on Cost of Power	$ 0.0824	75	$ 6.14	$ 0.0824	75	$ 6.14	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	2,000	$ -	-$ 0.0007	2,000	$ (1.40)	$ (1.40)		
CBR Class B Rate Riders	$ -	2,000	$ -	-$ 0.0001	2,000	$ (0.20)	$ (0.20)		
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -		
Low Voltage Service Charge	$ -	2,000	$ -		2,000	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 0.18	1	$ 0.18	$ -	1	$ -	$ (0.18)	-100.00%	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 49.00**			**$ 47.76**	**$ (1.24)**	**-2.53%**	
RTSR - Network	$ 0.0068	2,075	$ 14.11	$ 0.0073	2,075	$ 15.14	$ 1.04	7.35%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 0.0057	2,075	$ 11.83	$ 0.0061	2,075	$ 12.66	$ 0.83	7.02%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 74.94**			**$ 75.56**	**$ 0.63**	**0.84%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,075	$ 7.05	$ 0.0034	2,075	$ 7.05	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,075	$ 1.04	$ 0.0005	2,075	$ 1.04	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
TOU - Off Peak	$ 0.0650	1,300	$ 84.50	$ 0.0650	1,300	$ 84.50	$ -	0.00%	
TOU - Mid Peak	$ 0.0940	340	$ 31.96	$ 0.0940	340	$ 31.96	$ -	0.00%	
TOU - On Peak	$ 0.1340	360	$ 48.24	$ 0.1340	360	$ 48.24	$ -	0.00%	
Total Bill on TOU (before Taxes)			**$ 247.98**			**$ 248.60**	**$ 0.63**	**0.25%**	
HST	13%		$ 32.24	13%		$ 32.32	$ 0.08	0.25%	
Total Bill on TOU			**$ 280.21**			**$ 280.92**	**$ 0.71**	**0.25%**	

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	175	kWh
Demand	0	kW
Current Loss Factor	1.0373	
Proposed/Approved Loss Factor	1.0373	

	Current OEB-Approved			Proposed			Impact		
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change	
Monthly Service Charge	$ 0.64	1	$ 0.64	$ 0.65	1	$ 0.65	$ 0.01	1.56%	
Distribution Volumetric Rate	$ 4.6183	0.22	$ 1.02	$ 4.6668	0.22	$ 1.03	$ 0.01	1.05%	
Fixed Rate Riders	$ 0.01	1	$ 0.01	$ 0.01	1	$ 0.01	$ -	0.00%	
Volumetric Rate Riders	$ 0.0365	0.22	$ 0.01	$ 1.8022	0.22	$ 0.40	$ 0.39	4837.53%	
Sub-Total A (excluding pass through)			**$ 1.67**			**$ 2.08**	**$ 0.41**	**24.44%**	
Line Losses on Cost of Power	$ 0.1101	7	$ 0.72	$ 0.1101	7	$ 0.72	$ -	0.00%	
Total Deferral/Variance Account Rate Riders	$ -	0	$ -	-$ 0.2623	0	$ (0.06)	$ (0.06)		
CBR Class B Rate Riders	$ -	0	$ -	-$ 0.0300	0	$ (0.01)	$ (0.01)		
GA Rate Riders	$ -	175	$ -	$ 0.0014	175	$ 0.25	$ 0.25		
Low Voltage Service Charge	$ -	0	$ -		0	$ -	$ -		
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -		
Additional Fixed Rate Riders	$ 0.01	1	$ 0.01	$ -	1	$ -	$ (0.01)	-100.00%	
Additional Volumetric Rate Riders		0	$ -	$ -	0	$ -	$ -		
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2.40**			**$ 2.98**	**$ 0.58**	**24.13%**	
RTSR - Network	$ 2.0496	0	$ 0.45	$ 2.1855	0	$ 0.48	$ 0.03	6.63%	*In the manager's summary, discuss the reas*
RTSR - Connection and/or Line and Transformation Connection	$ 1.7789	0	$ 0.39	$ 1.9005	0	$ 0.42	$ 0.03	6.84%	*In the manager's summary, discuss the reas*
Sub-Total C - Delivery (including Sub-Total B)			**$ 3.25**			**$ 3.88**	**$ 0.64**	**19.61%**	
Wholesale Market Service Charge (WMSC)	$ 0.0034	182	$ 0.62	$ 0.0034	182	$ 0.62	$ -	0.00%	
Rural and Remote Rate Protection (RRRP)	$ 0.0005	182	$ 0.09	$ 0.0005	182	$ 0.09	$ -	0.00%	
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%	
Average IESO Wholesale Market Price	$ 0.1101	175	$ 19.27	$ 0.1101	175	$ 19.27	$ -	0.00%	
Total Bill on Average IESO Wholesale Market Price			**$ 23.47**			**$ 24.11**	**$ 0.64**	**2.71%**	
HST	13%		$ 3.05	13%		$ 3.13	$ 0.08	2.71%	
Total Bill on Average IESO Wholesale Market Price			**$ 26.52**			**$ 27.24**	**$ 0.72**	**2.71%**	