EB-2020-0007

BURLINGTON HYDRO RESPONSES TO BOARD STAFF INTERROGATORIES

1-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2021 Electricity Distributor Rate Applications webpage.

Response:

BHI has provided an updated RRWF in excel format and updated the models and appendices in the application in response to interrogatories. BHI files updated models and appendices as follows:

1. Attachment_Main_OEB_Chapter2Appendices_BHI_Revised
2. Attachment_2C_OEB_Chapter2Appendices_BHI_Revised
3. Attachment_2I_OEB_Chapter2Appendices_BHI_Revised
4. Attachment_2Z_OEB_Chapter2Appendices_BHI_Revised
5. Attachment_Load_Forecast_Model_BHI_Revised
6. Attachment_2021 LRAMVA Workform_BHI_Revised
7. Attachment_2021_RRWF_BHI_Revised
8. Attachment_2021_PILS_Workform_BHI_Revised
9. Attachment_DVA_Continuity_Schedule_BHI_Revised
10. Attachment_2021_Cost_Allocation_Model_BHI_Revised
11. Attachment_RTSR_Workform_BHI_Revised
12. Attachment_Tariff_Schedule_and_Bill_Impact_Model_BHI_Revised

1-Staff-2
Letters of Comment

Following publication of the Notice of Application, the OEB received seven letters of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

As of January 31, 2021, there are seven Letters of Comments posted on the OEB Website for BHI's Application. The responses are included as Appendix A: 1-Staff-2. BHI will continue to monitor the OEB website for Letters of Comments.

1-Staff-3

Ref: Exhibit 1, page 27

Question(s):

a) Please explain BHI's roles and responsibilities in support of the City's "Climate Action Plan" and "Climate Change Adaption Plan".
b) Please identify any capital and/or OM&A programs associated with these activities in support of the City's "Climate Action Plan" and "Climate Change Adaption Plan".

Response:

a) BHI is a member of the Stakeholders Advisory Committee for the City's Climate Action Plan.

b) There are no BHI capital or OM&A programs specifically associated with these activities.

1-Staff-4

Ref: Exhibit 1, page 47

Preamble:

BHI stated in the settlement agreement in its 2014 Cost of Service proceeding that "Burlington Hydro further agrees that it will, address the savings and/or other beneficial impacts resulting from these or other operational effectiveness initiatives, and the sustainability of savings and/or other beneficial impacts from those initiatives in its next Cost of Service or Custom IR application."[1]

In this Application, BHI identified productivity initiatives and improvements to its business process. OEB staff would like to understand how these identified initiatives were reflected in BHI's proposed OM&A and capital budget for the 2021 test year.

Question(s):

a) Please provide a list of existing productivity initiatives that are currently in place for the 2014-2020 period.

b) Please identify any new productivity initiatives that are planned to be implemented for the 2021-2025 rate period.

c) Is there any quantified information associated with existing and planned productivity initiatives? If so, please provide savings for each of the identified initiatives. Please explain:

    i. Whether it's one-time saving or persistent saving.
    ii. Whether its capital related or OM&A related initiative.
    iii. How savings for each initiative were calculated/estimated.

[1] EB-2013-0115, Proposed Settlement Agreement, May 6, 2014. Issue 6.2.

Response:

BHI provides Table 1 below in response to this interrogatory. The table has been expanded to satisfy the following interrogatories: SEC-7, CCC-7, CCC-24. BHI has implemented productivity initiatives and improvements to its business process as identified on page 47 of Exhibit 1 and page 25 of Exhibit 4. As identified in Table 1, the outcomes of these initiatives and improvements can be costs savings, avoided costs and/or improved outcomes for customers.

a) Please refer to Table 1 below for a list of existing productivity initiatives that are currently in place for the 2014-2020 period (column “Effective Date” = existing).

b) Please refer to Table 1 below – starting with row “New Initiatives”.

c) BHI does not track quantitative information associated with productivity initiatives at a consolidated level; or as part of its ongoing reporting. However, in an effort to quantify the dollar amounts associated with existing and planned productivity initiatives for the purposes of answering this interrogatory, BHI has estimated these amounts on a best-efforts basis. The dollar amounts provided are not necessarily costs savings resulting in lower overall expenditures; they could be avoided costs which avoid incurring expenditures in the future (e.g., FTE eliminations are avoided costs which have mitigated increases associated with FTE additions required to meet evolving business needs).

   i. Please refer to Table 1 below – column “One-time/Persistent Cost Savings or Avoided Costs”
   ii. Please refer to Table 1 below – column “OM&A or Capital”
   iii. Please refer to Table 1 below – column “Calculation/Comment”

Table 1

Efficiencies/Improvements	OM&A or Capital	Effective Date/ Existing or New in 2021	One-time/ Persistent Cost Savings or Avoided Costs	Application Reference	Calculation/ Comment
EXISTING INITIATIVES					
Position Elimination - Storekeeper	OM&A	2015 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - Stations Maintenance Technician	OM&A	2015 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - IT Support Analyst	OM&A	2016 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - Stations Lead Hand	OM&A	2016 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - CDM Manager	OM&A	2016 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - Executive Assistant	OM&A	2019 - existing	One-time	Ex 4 p25	One fully burdened FTE in Department
Position Elimination - Locator	OM&A	2019 - existing	Persistent	Ex 4 p25	One fully burdened FTE in Department
Mitigated Cost of Transition to Monthly Billing (e-billing)	OM&A	2017 - existing	Persistent	Ex 1 p47/Ex 4 p25	See 9-Staff-75 e)
Mitigated Cost of Transition to Monthly Billing (maintained headcount)	OM&A	2017 - existing	Persistent	Ex 1 p47/Ex 4 p25	One fully burdened FTE in Billing Department
Changed process for field collection services to (i) move to an hourly versus piece rate and (ii) eliminate hand delivery	OM&A	2019 - existing	Persistent	Ex 1 p47/Ex 4 p25	Refer to 9-Staff-77a)
Credit management process - Euler Hermes	OM&A	2019 - existing	Indeterminable	Ex 1 p47/Ex 4 p25	Cost is the annual insurance premium. Savings is the avoided loss of a potential large write-off.
Credit management process - Triggers	OM&A	2018 - existing	Indeterminable	Ex 1 p47/Ex 4 p25	automated customer account mangement system; early warning of changes in credit profile
Realized efficiencies in benefits program **GridSmartCity**	OM&A	2015 - 2016	One-time (2-years)	Ex 1 p47/Ex 4 p25	5.6% reduction to overall benefits
Realized efficiencies in benefits program **Collective Bargaining**	OM&A	2018 - 2019	One-time (1-years)	Ex 1 p47/Ex 4 p25	15% reduction to overall benefits; commencing July 1/2018 ending with provider switch June 1/2019
Realized efficiencies in benefits program **Provider Change**	OM&A	2019 - existing	One-time (2-years)	Ex 1 p47/Ex 4 p25	11% reduction to Extended Health and Benefits
Reduced vehicle operations and maintenance costs due to regularly scheduled maintenance of vehicles	OM&A	2014 - existing	Persistent	Ex 1 p47/Ex 4 p25	difference between actual cost and cost at compounded OEB inflation
Maintained OM&A costs in certain departments at lower than the cost of inflation since last rebasing application (Accounting, Facilities, Fleet, Metering, and Stations)	OM&A	2014 to 2021 existing	Persistent	Ex 1 p47/Ex 4 p25	difference between actual cost and cost at compounded OEB inflation (excluding above Fleet Maintenance and eliminated positions in these departments)
Implemented a new front end phone service including an enhanced Interactive Voice Response ("IVR") in 2016	OM&A	2016 - existing	n/a	Ex 1 p47/Ex 4 p25	no cost savings - customer service improvement through enhanced functionality; system at end of life and no longer supported by vendor
Replaced telephone infrastructure in 2019 and implemented cloud based call centre management	OM&A	2019 - existing	n/a	Ex 1 p47/Ex 4 p25	no cost savings or incremental costs
Implemented a new Payroll and Human Resource Information System ("HRIS") to consolidate core HR functions into one system;	OM&A	2019 - existing	Persistent	Ex 1 p47/Ex 4 p25	Difference between annual software fees old system vs. new
Implemented a new Geographic Information System ("GIS") in January 2020	OM&A	2020 - existing	n/a	Ex 1 p47/Ex 4 p25	no cost savings - business process improvements; system at end of life and no longer supported

Efficiencies/Improvements	2014	2015	2016	2017	2018	2019	2020	2021	Included in 2021 Revenue Requirement (per CCC-7)
EXISTING INITIATIVES									
Position Elimination - Storekeeper		$20,964	$83,853	$85,530	$87,240	$88,985	$90,765	$92,580	$92,580
Position Elimination - Stations Maintenance Technician		$8,376	$100,516	$102,526	$104,577	$106,668	$108,802	$110,978	$110,978
Position Elimination - IT Support Analyst			$83,853	$106,241	$108,367	$110,534	$112,745	$115,000	$115,000
Position Elimination - Stations Lead Hand			$72,040	$108,060	$110,221	$112,426	$114,675	$116,969	$116,969
Position Elimination - CDM Manager			$19,854	$79,419	$81,007	$82,627	$84,280	$85,965	$85,965
Position Elimination - Executive Assistant						$77,971	$95,437	$97,344	$97,344
Position Elimination - Locator						$8,100	$99,142	$101,125	$101,125
Mitigated Cost of Transition to Monthly Billing (e-billing)				$10,644	$40,241	$71,065	$95,307	$112,098	$112,098
Mitigated Cost of Transition to Monthly Billing (maintained headcount)				$91,304	$93,226	$95,098	$96,995	$99,322	$99,322
Changed process for field collection services to (i) move to an hourly versus piece rate and (ii) eliminate hand delivery						$22,400	$44,800	$44,800	$44,800
Credit management process - Euler Hermes						$0	$0	$0	$0
Credit management process - Triggers									$0
Realized efficiencies in benefits program **GridSmartCity**		$56,616	$56,616						$0
Realized efficiencies in benefits program **Collective Bargaining**					$54,000	$45,000			$0
Realized efficiencies in benefits program **Provider Change**						$91,700	$157,200	$65,500	$65,500
Reduced vehicle operations and maintenance costs due to regularly scheduled maintenance of vehicles		$8,074	$64,505	$49,272	$41,162	$117,130	$146,354	$150,703	$150,703
Maintained OM&A costs in certain departments at lower than the cost of inflation since last rebasing application (Accounting, Facilities, Fleet, Metering, and Stations)		$325,429	$368,356	$110,089	$422,980	$393,313	$67,518	$79,283	$79,283
Implemented a new front end phone service including an enhanced Interactive Voice Response ("IVR") in 2016									$0
Replaced telephone infrastructure in 2019 and implemented cloud based call centre management									$0
Implemented a new Payroll and Human Resource Information System ("HRIS") to consolidate core HR functions into one system;								$10,000	$10,000
Implemented a new Geographic Information System ("GIS") in January 2020							$0	$0	$0

Efficiencies/Improvements	OM&A or Capital	Effective Date/ Existing or New in 2021	One-time/ Persistent Cost Savings or Avoided Costs	Application Reference	Calculation/ Comment
NEW INITIATIVES					
Implementing a new Customer Information System ("CIS")	OM&A	2021 - new	n/a	Ex 1 p47/Ex 4 p25; Ex 4, Appendix B	no cost savings - business process improvements; improved customers service
Implementing a new Enterprise Resource Planning System ("ERP") in 2023	Capital/OM&A	2023 - new	Undetermined	Ex 1 p47/Ex 4 p25	undetermined at this time
Leveraged an ACA to identify assets in Very Poor and Poor condition and mitigate outages as a result of failures due to defective equipment	Capital	2021 - new	Undetermined	Ex 1 p47	not implemented until 2021 planning year
Introduced two new planning tools – the Program Evaluation Tool and Project Prioritization Tool	Capital	2021 - new	Undetermined	Ex 1 p47	not implemented until 2021 planning year
File Nexus - digitization	OM&A	2021 - new	Undetermined	Ex 1 p47	not implemented until 2022 planning year

Efficiencies/Improvements	2014	2015	2016	2017	2018	2019	2020	2021	Included in 2021 Revenue Requirement (per CCC-7)
NEW INITIATIVES									
Implementing a new Customer Information System ("CIS")									$0
Implementing a new Enterprise Resource Planning System ("ERP") in 2023									
Leveraged an ACA to identify assets in Very Poor and Poor condition and mitigate outages as a result of failures due to defective equipment									$0
Introduced two new planning tools – the Program Evaluation Tool and Project Prioritization Tool									$0
File Nexus - digitization									$0

1-Staff-5

Ref: Exhibit 1, page 78

Question(s):

a) Please explain any changes made to the 2021 test year OM&A budget and 2021-2025 capital expenditures after BHI's Board of Directors' review in September 2020.

Response:

a) No changes were made to the 2021 test year OM&A budget and 2021-2025 capital expenditures from BHI's Board of Directors' review in September 2020 until BHI filed its Application on October 30, 2020.

   Since filing its Application BHI has updated its capital forecast for material changes. These changes have impacted the 2020 Bridge Year, 2021 Test Year and 2022 forecasted capital expenditures. Please refer to BHI's response to 2-Staff-9 a) for updated 2020-2022 capital expenditures.

1-Staff-6

Ref: Exhibit 1, page 81

Question(s):

a) Please clarify whether BHI has included any impacts of the COVID emergency in its proposed 2021 OM&A. If so, please specify the impacts.

b) Please clarify whether BHI has included any impacts of the COVID emergency in its proposed 2021 capital expenditures. If so, please specify the impacts.

c) Please provide entries BHI has recorded in each of the COVID-19 sub-accounts established by the OEB.

   i. Please explain the types of costs/lost revenues associated with the amounts that BHI has recorded in each sub-account.
   ii. Please discuss any other types of costs/lost revenues/savings that BHI anticipates recording in the sub-accounts.

Response:

a) BHI provides the impacts of COVID-19 on OM&A in the 2020 Bridge Year and the 2021 Test Year below; which does not include any COVID-19 impacts recorded in the COVID-19 sub accounts – for these refer to part c) below. Note that the 2020 Bridge Year, in addition to the 2021 Test Year has been provided to satisfy interrogatories CCC-6 and 1-SEC-5.

   2020 Bridge Year
   - BHI increased its bad debt provision in 2020 to account for additional write-offs for small commercial customers (Exhibit 4, page 71)

   2021 Test Year
   - BHI has not included any impacts of the COVID emergency in its proposed 2021 OM&A.

b) BHI provides the impacts of COVID-19 on Capital in the 2020 Bridge Year and the 2021 Test Year in Table 1 below. Note that the 2020 Bridge Year, in addition to the 2021 Test Year has been provided to satisfy interrogatories CCC-6 and 1-SEC-5.

2020 Bridge Year

- COVID-19 caused delays in, and in some circumstances increases in the costs of, capital projects as follows:
    - Delay/cancellation of general service system access projects (decrease $440k)
    - Delay in switch replacement to 2021 (decrease $150k)
    - Delay in Region projects to 2021 (decrease $462k)
    - Delay in and increase in costs of, new CIS (increase $176k); resources diverted to implementation, programming and testing of public policy changes (RPP optionality) and COVID-related electricity bill relief.

2021 Test Year

- Some projects delayed in 2020 will be completed in 2021
    - General system access projects (increase $100k)
    - Switch replacement (increase $120k)
    - Region projects shifted from 2020 to 2021 (increase $677k)
    - Delay in and increase in costs of, new CIS (increase $216k); resources diverted to implementation, programming and testing of public policy changes (RPP optionality) and COVID-related electricity bill relief.

Please refer to BHI's response to 2-Staff-9 for more details on revisions to capital expenditures since the Application was filed.

c) BHI has recorded entries in the COVID-19 sub-accounts established by the OEB as provided in Table 1 below. BHI is applying carrying charges to each sub-account but has not included these in Table 1.

Please note the costs/lost revenues in the below table are not all inclusive to December 31, 2020 as BHI has not completed its year-end processing.

Table 1

OEB Account - Types of Costs/Lost Revenues	Debit	Credit	One-Time/ Ongoing
Impacts Arising from COVID-19 Emergency - Lost Revenues	***Account 1509***	***Account 4080***	
Lost distribution revenue associated with COVID	$626,844	($626,844)	Ongoing
Impacts Arising from COVID-19 Emergency - Other Costs	***Account 1509***	***Account 1005***	
Incremental OM&A costs incurred due to COVID-19	*$522,893*	*($522,893)*	
Types of Costs:			
Joesph Brant COVID-19 Field Hospital	$38,844		One-time
Additional janitorial services (office cleaning)	$11,557		Ongoing
Additional safety supplies (masks,gloves,hand sanitizer etc.)	$29,181		Ongoing
Additional subscriptions (Zoom, Self-Screening App)	$6,992		Ongoing
Additional computer supplies (cameras,monitors)	$6,742		Ongoing
Additional safety signs & posters (COVID-19 protocols)	$7,834		One-time
Offsite control room (setup, trailer rental, generator fuel)	$44,507		Ongoing
Portable Toilets & Sinks	$20,379		Ongoing
Rental of Double Shower Trailer	$32,300		Ongoing
Fleet Costs (one person per vehicle)	$310,100		Ongoing
Additional miscellaneous supplies	$14,457		Ongoing
OM&A cost savings due to COVID-19	*($27,540)*	*$27,540*	
Types of Cost Savings:			
Insurance premiums credit refund	($27,540)		One-Time
Impacts Arising from COVID-19 Emergency - Bad Debts	***Account 1509***	***Account 1100***	
Incremental Bad Debt arising from COVID-19	n/a	n/a	

i. Please refer to Table 1 for details of the types of costs/lost revenues associated with each COVID-19 sub-account.

ii. BHI anticipates that it will incur the following costs in the sub-accounts as follows:

   a. incremental bad debts arising from COVID-19. Bad debt write-offs related to delinquencies in 2020 as a result of COVID-19 will be recorded in 2021 and as such no entry has been made in the COVID-19 account. BHI's current process has a 12-month lag from "final bill" to "write-off" allowing for collection activities to occur. Similarly, any bad debt write-offs related to delinquencies in 2021 as a result of COVID-19 will not occur until 2022.

   b. additional financing costs associated with lower cash balances and higher use of BHI's operating line of credit due to an increase in accounts receivable aging.

1-Staff-7

Ref: Exhibit 1, page 113

Question(s):

a) Please explain reasons for the lower total cost per customer in 2017 compared to other years over the 2015-2019 period.

b) Please explain reasons for the higher total cost per customer in 2019 compared to other years over the 2015-2019 period.

Response:

BHI provides Table 1 below for ease of reference which identifies the total capital and operating costs per customer as published by the OEB in the Pacific Economics Group ("PEG") Benchmarking Reports.

Table 1

Description	2015	2016	2017	2018	2019
Capital Cost	$23,858,572	$23,902,572	$23,140,723	$24,594,385	$26,037,954
Operating Cost	$17,198,232	$17,539,020	$17,672,918	$18,025,935	$19,043,936
Total Cost	**$41,056,804**	**$41,441,591**	**$40,813,641**	**$42,620,320**	**$45,081,890**
# of Customers	66,656	66,824	67,122	67,940	68,205
Total Cost per Customer	**$616**	**$620**	**$608**	**$627**	**$661**
Capital Cost per Customer	$358	$358	$345	$362	$382
Operating Cost per Customer	$258	$262	$263	$265	$279

a) The lower total cost per customer in 2017 compared to other years over the 2015-2019 period is driven by capital costs which were $345 per customer. BHI's gross plant additions increased from 2016 to 2017, however this was more than offset by a decrease in the Weighted Average Cost of Capital ("WACC") from 6.28% in 2016 to 5.67% in 2017.[1] The WACC is used to by PEG to determine capital price which is a component of actual capital cost.

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

b) The higher total cost per customer in 2019 compared to other years over the 2015-2019 period is driven by both capital costs and operating costs.

Capital Costs

BHI's gross capital additions in 2019 were $20.6M as compared to an average of $12.2M over 2015-2019. The main drivers of the higher capital cost in 2019 are:

- System Access: an increase in new subdivisions; underground development in the downtown core; Hydro One CCRA true-up payments; the commencement of the Metrolinx Regional Electrification Project; and an increase in road widening projects for the Region of Halton;
- System Service: increased expenditures on the NE Burlington TS Egress project; and
- General Plant: increased expenditures for a new GIS and CIS; and an increase in facilities expenditures due to the need refurbish/renovate deteriorated areas of BHI's head office building.

Please refer to pages 53-66 of Exhibit 2 in the Application for further details.

Operating Costs

Operating costs in 2019, as defined in the PEG benchmarking model, were $19.0M as compared to an average of $17.6M over 2015-2019. 2016-2018 operating costs increased by less than the rate of inflation on average, as compared to 2015. The main drivers of the higher operating cost in 2019 are:

- Consulting Fees and Computer Software
  - Engineering – page 99 Exhibit 4 (2018-2019 Variance Explanation)
  - Information Services – page 114 Exhibit 4 (2018-2019 Variance Explanation)
- Other Miscellaneous
  - PCB Cleanup/Disposal; transformer repairs; safety equipment, training and programs

1-Staff-8

Treatment of Leases
Ref 1: Exhibit 1/Appendix F
Ref 2: Exhibit 1/Appendix G

Preamble:

Note 10 Lease Liabilities of BHI's 2019 Audited Financial Statements (AFSs) in Exhibit 1 Appendix F provides the following table:

	Vehicles	Computer software	Total
Right-of-use assets			
Cost			
Balance at January 1, 2019	$ 533,418	$ 265,958	$ 799,376
Transitional adjustment	146,266	131,545	277,811
Balance at December 31, 2019	$ 679,684	$ 397,503	$ 1,077,187
Accumulated depreciation			
Balance at January 1, 2019	$ 195,586	$ 166,233	$ 361,819
Transitional adjustment	48,223	83,965	132,188
Additions	66,729	99,375	166,104
Balance at December 31, 2019	$ 310,538	$ 349,573	$ 660,111
Carrying amounts			
At December 31, 2019	$ 369,146	$ 47,930	417,076
At December 31, 2018	337,832	99,725	437,557

It also states that "Effective January 1, 2019, the Corporation adopted IFRS 16 and transitioned its operating leases to finance leases. The leased assets secure lease liabilities (see note 10). At December 31, 2019, the net carrying amount of the lease liabilities related to the leased assets was $215,210 (2018 – $270,356)".

From the review of Exhibit 1, Appendix G Reconciliation AFSs with Regulatory Financial Results, OEB staff notes that the current portion of lease liabilities of $113,638 is not recognized in the regulatory financial results for 2019.

Question(s):

a) Please confirm OEB staff's observation.

b) If confirmed, please explain where the current portion of lease liabilities is recorded in regulatory financial results for 2019?

c) Please explain how the leased assets (vehicles and computer software) are recognized in the revenue requirement of this rate application and how the treatment of these assets is different than the one in BHI's last cost of service application?

Response:

a) BHI does not confirm OEB Staff's observation. The current portion of lease liabilities of $113,638 is recognized in the regulatory financial results for 2019. The carrying amount of these liabilities was included in the current portion of long-term debt ($1,441,038) in the "RRR Balances" column of Appendix G in Exhibit 1. The current portion of lease liabilities of $113,638 was erroneously recorded in USoA 2260 instead of USoA 2285 in 2019.

b) Please refer to BHI's response to part a) above. The current portion of lease liabilities of $113,638 was erroneously recorded in USoA 2260 instead of USoA 2285 in 2019.

c) The leased assets (vehicles and computer software) are recognized in the revenue requirement of this rate application as part of the 2021 Test Year opening rate base. The principal portion of lease payments is recognized in depreciation expense. The treatment of these assets is different than in BHI's 2014 Cost of Service Application, in which BHI did not recognize leased assets in rate base; and lease payments were recorded in operating expenses.

2-Staff-9

Ref: Exhibit 2/Section 2.2 Capital Expenditures

Question(s):

a) Please provide breakdown of forecasted capital expenditures by capital projects in Appendix 2-AA format for each year over the 2022-2025 period in Excel.

b) Using Appendix 2-AA format, please provide the list of capital projects and associated capital expenditures resulting from each step (step 1. Needs Assessment to step 4. Management and Board Review & Approval) of the capital expenditure planning process (as illustrated in Figure 5.4-1 on page 120 of the DSP) for the 2021 test year in Excel.

c) The proposed net capital expenditures for 2021 is about 32% higher than the average level of forecasted capital expenditures for 2022-2025. Has BHI considered a more balanced pacing of its capital plan during the DSP period? If so, please explain what has been done.

d) Please provide BHI's forecasted in-service additions by investment categories (System Access, System Renewal, System Service, General Plant) for the 2021 test year.

e) Please explain BHI's approach to forecasting capital expenditures and related in-service additions.

f) Please provide the updated year to date actual capital expenditures for 2020 by investment categories. Please specify how many months are actual vs. forecast.

Response:

a) BHI provides a recast Appendix 2-AA to include the 2022-2025 period in Excel format, attached as IR_Attachment_2-Staff-9a_BHI. Please note this attachment has two tabs, as follows:

   1. 'Tab1_2-AA_Recast_Oct30_2020' contains a recast Appendix 2-AA per BHI's original Application filed October 30, 2020.

   2. 'Tab2_2-AA_Recast_Feb1_2021' contains a recast Appendix 2-AA per BHI's updated capital expenditure forecast in response to interrogatories. Tab2_2-AA_Feb 1_2021 also contains an update to 2015 capital expenditures related to vehicles. These amounts were included in BHI's fixed asset continuity schedules

(OEB Appendix 2-BA) and rate base but were erroneously omitted from BHI's capital expenditure summaries.

Further, BHI has included the historical period (2014-2019), 2020 Bridge Year, and 2021 Test Year in both tabs of the attachment for ease of reference and to facilitate streamlined responses to related interrogatories.

b) BHI provides a list of capital projects and associated capital expenditures resulting from each step of the capital expenditure planning process for the 2021 test year in Excel format, attached as IR_Attachment_2-Staff-9b_BHI.

c) BHI considers the proposed capital plan to be appropriately balanced. BHI's proposed level of net capital expenditures was developed to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives. BHI considered different pacing alternatives for non-mandatory projects, as described in section 5.3.1(b).2 of the DSP (page 68 of 186) and made changes to its draft capital plan as necessary, to ensure the pacing reflected customer needs and preferences, as described on pages 124-125 of section 5.4.1(b).1 of the DSP.

d) Please refer to BHI's response to 2-SEC-16 for BHI's forecasted in-service additions by investment categories for the 2021 Test Year.

e) BHI's approach to forecasting capital expenditures is described in the Capital Expenditure Planning Process Overview Section 5.4.1 of the DSP. BHI completes most of its distribution plant capital projects in the year that the expenditure occurs and uses the forecasted capital expenditure year to forecast in-service additions. For multi-year projects BHI adjusts its in-service additions forecast based on when the asset is expected to enter service (e.g. for a multi-year IT project).

f) BHI provides July 2020 year to date actual capital expenditures by investment category in Table 1 below, consistent with BHI's original filing on October 30, 2020. BHI has not updated its 2020 capital forecast for actuals as they are not available – BHI's year end process is not complete. However, BHI has updated its capital forecast for material changes since October 30, 2020, as identified in appendices 2-AA and 2-AB of BHI's updated OEB Chapter 2 Appendices, filed as:

Attachment_Main_OEB_Chapter2Appendices_Revised_BHI.

Table 1

Investment Category	July 2020 YTD
System Access	$2,359,059
System Renewal	$1,403,093
System Service	$286,736
General Plant	$1,465,709
Total net capital expenditures	**$5,514,597**

2-Staff-10

Ref: Exhibit 2/Section 2.2.3 Policy Options for the Funding of Capital

Preamble:

BHI proposed ACM funding of $2.0 million for the implementation of a new ERP system. The forecasted cost is $1.0 million in both 2022 and 2023.

Question(s):

a) Please provide a breakdown of the forecasted project cost of $2.0 million.

b) Please explain the basis of assuming a useful life of five years for this asset.

c) BHI expects this ERP replacement project to commence in 2022 and be in service in 2023. Please explain in which year BHI plans to start collecting ACM funding for this project (i.e. 2022 rate year or 2023 rate year).

d) In the Material Investment Summary Document for this ERP replacement project, BHI stated that "A thorough analysis of each project alternative will be completed as part of the business case." Please explain why it's a prudent request of ACM funding without a thorough analysis of each project alternative completed in this Application.

e) In the Material Investment Summary Document for this ERP replacement project, BHI stated that "A business case will be developed prior to the start of the RFP process." Please explain why it's a prudent request of ACM funding without a business case developed in this Application.

f) When does BHI plan to start the RFP process?

Response:

a) BHI does not have a breakdown of the forecasted project cost of $2.0MM at this time. BHI planned to file a business case for the ERP replacement project as part of this Application in order to demonstrate prudence as per the Board's criteria for recovery of ACM amounts[1]. As described in section 1.2.7 of Exhibit 1, the COVID-19 pandemic has had a significant impact on BHI's operations, and resources have been required to address key customer, operational and staffing issues. Furthermore, IT resources whose subject matter expertise is required to inform the development of the ERP business case

[1] EB-2014-0219 *New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014.

are focused on the successful implementation of BHI's new CIS, which has been delayed due to COVID-19. BHI has yet to complete the ERP replacement business case due to these factors.

While BHI is able to demonstrate that it meets the ACM criteria for materiality and need (means test, discrete project, outside of the base upon which rates were derived), it acknowledges it cannot demonstrate prudence at this time. BHI respectfully withdraws its request for ACM funding in the Application.

BHI confirms it still has a business need for this project, as outlined in the Material Investment Summary Document filed in Appendix 1 of the DSP, and anticipates filing an ICM request as part of a subsequent IRM application.

b) to f) Please refer to BHI's response part a) above.

2-Staff-11

Ref: Exhibit 2 – page 78 of 94

Question(s):

a) Has Burlington Hydro estimated any future true-up payments to Hydro One in relation to Tremaine TS within the rebasing period?

Response:

a) No, BHI has not estimated any future true-up payments to Hydro One in relation to the Tremaine TS within the rebasing period.

2-Staff-12

Ref: Exhibit 2 – Rate Base, DSP page 34

Question(s):

a) Please identify measures that are not tracked in the OEB's generic scorecard.

b) For DSP Performance Measures with a target of "Monitor" or "Improve", please explain how BHI plans to evaluate its performance on these measures.

c) In light of the OEB's Activity and Program Based Benchmarking Initiative,[1] has BHI considered including cost efficiency and effectiveness measures to track unit cost information for its main OM&A and capital programs/projects?

d) The DSP implementation progress metric will measure BHI's DSP implementation of planned total capital expenditures vs. actuals, has BHI considered a metric to measure the completeness of planned units vs. actuals for its major asset classes?

Response:

a) DSP Performance Measures identified by BHI that are not tracked in the OEB's generic scorecard are as follows:

   i. Emergency Response;
   ii. Provides Consistent Reliable Energy (Survey Results);
   iii. CAIDI – excluding LOS and MED;
   iv. Customer Hours of Interruption due to Defective Equipment; and
   v. Asset condition (% of Assets in Poor and Very Poor Condition) for Wood Poles, MS Feeder Cables and Station Switchgear.

b) BHI plans to evaluate its performance on measures with a target of "Monitor" by considering whether the measure is improving or worsening, taking into consideration the factors that contribute to the performance. For example, BHI strives to continuously improve its asset management and capital expenditure planning processes in order to improve its Total Cost per Customer measure; however, BHI has experienced a cumulative increase of more than $8 million in System Access projects from 2015 to 2019 which has impacted its ability to invest in System Renewal projects. Several of BHI's asset categories have a significant number of assets in Fair, Poor or Very Poor

[1] EB-2018-0278

condition, which require replacement over the next five years, which puts upward pressure on the Total Cost per Customer measure. Factors such as asset condition, reliability performance, safety and the level of mandatory System Access projects will be considered in evaluating performance against this measure and whether corrective action is required.

BHI plans to evaluate its performance on measures with a target of “Improve” by assessing whether the percentage of wood poles, MS feeder cables, and station switchgear in Very Poor and Poor health condition is decreasing over the 2021 to 2025 DSP period.

c) No, BHI has not considered including cost efficiency and effectiveness measures to track unit cost information for its main OM&A and capital programs/projects. Any consideration of tracking unit cost information for BHI’s main OM&A and capital programs/projects is dependent upon data availability and BHI’s system capabilities; in addition to the results from the OEB’s Activity and Program-based Benchmarking Initiative.

d) No, BHI has not considered a DSP implementation progress metric in this Application which measures the completeness of planned units vs. actuals for its major asset classes.

2-Staff-13

Ref: Exhibit 2 – Appendix 10: 2019 Asset Condition Assessment Report

Question(s):

a) For each of the recommendations identified in section 5 of the report, please specify:

  i. Whether BHI plans to implement the recommendation.
  ii. If yes to part i), please specify the action plan of implementing each recommendation.
  iii. If yes to part i), please specify when BHI plans to start and complete the implementation of each recommendation.

Response:

a) BHI plans to implement the following recommendations from section 5 of the 2019 Asset Condition Assessment Report.

Table 1

Recommendation	Implementation Plan	Implementation Timing
Health Index Improvements	Implement IR Scanning for station power transformers and incorporate results into future Health Index formulation.	2021
Health Index Improvements	Implement Cable Condition testing for underground primary cables and incorporate results into future Health Index formulation.	2021

BHI needs to evaluate all other recommendations before making a decision on implementation.

2-Staff-14

Ref: Exhibit 2 – Rate Base, DSP p.45

Question(s):

a) Regarding working capital allowance, please reconcile Table 33 in Exhibit 2, Section 2.1.3, with Appendix 2-JA for the following OM&A items:

   i. Operations
   ii. Administrative and General

Response:

a) BHI provides a reconciliation between Table 33 in Exhibit 2, Section 2.1.3 and Appendix 2-JA for the following OM&A items:

   i. The 2021 Test Year Operations expense is $572,068 higher in Table 33 due to an error – these expenses should have been included in Administrative and General expenses. All other years reconcile between the two schedules. BHI provides a revised Table 33 reflecting this correction in Table 1 below.

   ii. The 2021 Test Year Administrative and General expense is $572,068 lower in Table 33 due to the error described in part i. In addition, the Administrative and General expense in Appendix 2-JA includes LEAP funding, which is broken out separately in Table 33.

Table 1 (revised Table 33, Exhibit 2)

Description	2014 CoS (EB-2013-0115)	2014 Actual (CGAAP)	2014 Actual (MIFRS)	2015 Actual (MIFRS)	2016 Actual (MIFRS)	2017 Actual (MIFRS)	2018 Actual (MIFRS)	2019 Actual (MIFRS)	2020 Bridge Year	2021 Test Year
Distribution Expenses										
Operations	$5,370,488	$6,119,958	$5,778,866	$5,320,446	$5,138,246	$3,962,310	$4,000,062	$4,566,045	$4,381,070	$4,261,688
Maintenance	$3,864,317	$2,609,624	$2,609,624	$3,701,172	$4,198,648	$5,098,439	$5,395,369	$4,966,885	$5,087,113	$6,004,924
Customer Services	$2,326,477	$2,356,794	$2,356,794	$2,285,579	$2,266,275	$2,246,596	$2,648,912	$2,278,862	$2,877,786	$2,999,028
Community Relations	$19,500	$10,205	$10,205	$27,980	$54,320	$35,026	$25,392	$15,271	$31,803	$36,800
Administration	$6,068,268	$6,072,470	$6,016,772	$6,346,784	$6,396,792	$6,787,018	$6,702,010	$7,226,879	$7,350,129	$8,148,335
Donations - LEAP	$37,950	$74,279	$74,279	$34,603	$34,603	$34,603	$34,603	$34,603	$34,603	$47,000
Property Taxes	$273,559	$280,668	$280,668	$289,384	$295,949	$311,741	$324,576	$331,720	$335,996	$341,790
Less Allocated Depreciation in OM&A	($384,026)	$0	$0	($55,848)	($33,021)	($21,446)	($332,135)	$0	$0	$0
Total Distribution Expenses	**$17,576,533**	**$17,523,998**	**$17,127,208**	**$17,950,101**	**$18,351,812**	**$18,454,288**	**$18,798,789**	**$19,420,264**	**$20,098,500**	**$21,839,565**
Power Supply Expenses	$190,702,260	$184,198,618	$184,198,618	$197,721,069	$221,163,950	$181,237,350	$175,593,632	$170,813,945	$178,732,829	$191,444,505
Total Expenses for Working	**$208,278,793**	**$201,722,616**	**$201,325,825**	**$215,671,170**	**$239,515,762**	**$199,691,638**	**$194,392,421**	**$190,234,210**	**$198,831,329**	**$213,284,070**
Working Capital Factor	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	7.5%
Total Working Capital Allowance	**$27,076,243**	**$26,223,940**	**$26,172,357**	**$28,037,252**	**$31,137,049**	**$25,959,913**	**$25,271,015**	**$24,730,447**	**$25,848,073**	**$15,996,305**

2-Staff-15

Ref: Exhibit 2 – Rate Base, DSP pp. 49, 135-140

Preamble:

Table 5.2-13 shows that the capital expenditures over historical period were on average 20% higher than planned.

Question(s):

a) Please provide a breakdown by capital projects for the System Renewal category to show the budgeted amount, the actual spending and the variance for each of the historical years (2014-2019). Please explain any material variance.

b) Please provide a breakdown by capital projects for the General Plant category to show the budgeted amount, the actual spending and the variance for each of the historical years (2014-2019). Please explain any material variance.

c) There is a consistent overspending in the System Renewal category during 2014-2019. Please explain what actions BHI has taken to ensure the actual spending is as close to the forecasted costs as possible.

d) There is a consistent overspending in the General Plant category during 2014-2019. Please explain what actions BHI has taken to ensure the actual spending is as close to the forecasted costs as possible.

e) Please explain what practices are in place, or BHI plans to do, for the 2021-2025 rate period, to ensure the actual capital expenditures are in line with the forecasted costs.

f) Please provide BHI's actual capital expenditures on the implementation of a new Geographic Information System (GIS) over 2019 and 2020.

g) Please provide BHI's actual capital expenditures on the implementation of a new Customer Information System (CIS) over 2019 and 2020.

<u>Response:</u>

a) Please refer to BHI's response to 1-SEC-8 for a breakdown by capital project for the System Renewal category (2014-2018). BHI did not produce its 2019 budget amounts by capital project for this application; however, material variances against BHI's internal budget are provided in section 5.4.2.1 of the DSP (pages 139-140).

b) Please refer to BHI's response to 1-SEC-8 for a breakdown by capital project for the General Plant category. BHI did not produce its 2019 budget amounts by capital project for this application; however, material variances against BHI's internal budget are provided in section 5.4.2.1 of the DSP (pages 139-140).

c) BHI's higher expenditures in the System Renewal category in 2014-2019 as compared to the DSP were driven by higher than planned expenditures associated with the replacement of wood poles, underground cable and switch gear; a high proportion of which were replaced on a reactive basis. Replacing assets on a reactive basis makes it difficult to predict when assets require replacement which can cause increases in actual spending as compared to forecast when unexpected failures occur.

BHI is taking a more proactive approach to system renewal over the 2021 to 2025 period, targeting assets in the worst condition.[1] BHI plans to increase the pacing of renewal programs for some assets (e.g. wood poles, station circuit breakers, station transformers); and introduce proactive renewal programs for other assets, which were historically replaced on a reactive basis (e.g. underground cables, station primary switchgear).[2]

Pre-emptive replacement targeting assets in Very Poor or Poor condition and that are at the end of their service life will avoid the emergency premium of reactively replacing an asset that fails in the field.[3] BHI has adopted this more proactive approach and made several changes to its asset management process - as identified on page 55 of the DSP. In doing so, BHI will ensure that actual spending is as close to the forecasted costs as possible.

d) BHI's higher expenditures in the General Plant category in 2014-2019 as compared to the DSP was driven by unforeseen events such as the 2013 ice storm that led to BHI investing in an Outage Management System ("OMS"); health and safety concerns leading to renovations to deteriorated areas of BHI facilities; and Ontario Cyber Security Framework compliance requirements requiring investment in new cyber security tool sets. BHI has made several changes to its asset management process - as identified on page 55 of the DSP - which will help ensure that actual spending is as close to the forecasted costs as possible.

e) BHI has made several changes to its asset management process - as identified on page 55 of the DSP - which will help ensure that actual capital expenditures are in line with the forecasted costs.

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[1] DSP, p54
[2] Ibid, p54-55
[3] DSP, p20, p54

f) BHI provides capital expenditures on the implementation of a new Geographic Information System (GIS) over 2019 (actual) and 2020 (estimate) in Table 1 below.

Table 1

Description	2019	2020
Geographic Information System (GIS)	$344,595	$394,818

2020 actual data is not available because BHI's year end processing is not complete. However, BHI provides an updated 2020 estimate for the GIS implementation in Table 1 based on its updated capital expenditure forecast in response to interrogatories.

g) BHI provides capital expenditures on the implementation of a new Customer Information System (CIS) over 2019 (actual) and 2020 (estimate) in Table 2.

Table 2

Description	2019	2020
Customer Information System (CIS)	$1,258,142	$1,106,145

2020 actual data is not available because BHI's year end processing is not complete. However, BHI provides an updated 2020 estimate for the CIS implementation in Table 2 based on its updated capital expenditure forecast in response to interrogatories.

2-Staff-16

Ref: Exhibit 2 – Rate Base, DSP pp. 44-45

Preamble:

Table 5.2-11 shows reliability performance by cause over the historical period.

Question(s):

a) Do the values in Table 5.2-11 include Major Event Days (MED) or not? If so, please explain which row MED is included.

b) Please discuss if defective equipment was by far the major cause of customer interruptions and what is the basis for the target in Table 5.2-12 on page 48 as this target is higher than the number of customer hours for all years of the historical period (with the exception of 2015).

c) BHI stated that "Outages caused by defective equipment are trending upwards over the past five years…". Please provide a further breakdown by year and equipment type (same equipment types as the ACA) to identify assets that are driving the increase in outages.

Response:

a) No, the values in Table 5.2-11 do not include Major Event Days.

b) Defective Equipment was the top contributor to customer interruptions - excluding scheduled outages and loss of supply - over the 2015 to 2019 period. The basis for the target in Table 5.2-12 on page 48 is the 2015 to 2019 average number of customer hours interrupted per year due to Defective Equipment. This target is higher than the number of customer hours interrupted due to Defective Equipment in 2015, 2017 and 2018 but not in 2016 and 2019.

c) BHI provides a further breakdown of Defective Equipment reliability performance by equipment type for the years 2018 to 2020 in Table 1 below. This data is not available for the years 2014 to 2017 as it was not tracked to this level of detail by Control Room staff (the Control Room supervisor position was vacant during this period), and cannot be provided with reasonable effort.

Table 1

ACA Equipment Type	Measure	2018	2019	2020
Wood Pole	# of interruptions	3	5	6
	Cust. Interruptions	5	1,633	4,442
	Cust. Hours	16	4,921	752
Underground Primary Cable	# of interruptions	27	29	20
	Cust. Interruptions	4,079	4,682	1,930
	Cust. Hours	7,910	12,923	5,494
Pole-Mount Transformer	# of interruptions	4	7	7
	Cust. Interruptions	40	85	60
	Cust. Hours	172	140	344
Pad-Mount Transformer	# of interruptions	24	23	37
	Cust. Interruptions	302	1,400	907
	Cust. Hours	738	3,439	3,312
Submersible Transformer	# of interruptions			4
	Cust. Interruptions			172
	Cust. Hours			613
Switchgear	# of interruptions	4	4	
	Cust. Interruptions	1,425	1,318	
	Cust. Hours	932	1,224	
Overhead Switch	# of interruptions	80	71	93
	Cust. Interruptions	9,196	11,768	15,136
	Cust. Hours	11,408	18,020	15,172
Protective Relay	# of interruptions		2	1
	Cust. Interruptions		2,929	89
	Cust. Hours		1,166	40
Other	# of interruptions	10	8	1
	Cust. Interruptions	179	313	5
	Cust. Hours	330	576	7
Total # of interruptions		**152**	**149**	**169**
Total Cust. Interruptions		**15,226**	**24,128**	**22,741**
Total Cust. Hours		**21,506**	**42,409**	**25,733**

2-Staff-17

Ref: Exhibit 2 – Rate Base, DSP pp.69, 101, 115, 118, 126

Preamble:

BHI uses its Evaluation Tool to perform an economic evaluation of alternatives for its non-mandatory capital programs over $120k. The outcome of this evaluation step is a recommended alternative for each investment need.

Question(s):

a) Please explain the basis of selecting $120k as the threshold of conducting an economic evaluation analysis for non-mandatory capital programs.

b) Please provide BHI's definitions of a capital program vs. a capital project and explain if any difference between these two terms in the Evaluation Tool.

c) Using the Pole Replacement program as an example, please provide supporting calculations performed by the Evaluation Tool. Please specify the cost and benefit assumptions and data used for each alternative, and the calculated net present value for each alternative.

d) On page 68 of the DSP, it was stated that "BHI planners developed alternatives to eight non-mandatory investments in the draft plan and asked customers for feedback on which alternative they preferred as part of customer engagement Phase II." Please provide NPV for each alternative calculated for each capital program as listed in Table 5.4-8 (page 125 of DSP). Please provide detailed Evaluation tool results for reliability, safety and cost benefits for each of the alternatives.

<u>Response:</u>

a) BHI selected $120,000 as the threshold of conducting an economic evaluation analysis for non-mandatory capital programs because it wanted to seek customer feedback on three types of equipment housed within its distribution stations – breakers, switchgears and relays. Although these assets were consolidated for the purposes of customer engagement[1], they were segregated for the purposes of alternatives evaluation in the Evaluation Tool because their cost and benefit streams were different from one another. Capital expenditures in the draft plan for breakers and relays were $120,000 each.

[1] p 15, Residential Workbook, Appendix 12 of the DSP

b) BHI considers projects to be one-time investments with a discrete scope of work and timeline. Examples of projects in BHI's 2021 Test Year include the Dundas St. road widening project and the replacement of BHI's standby generator. BHI considers a program to be a group of related projects which are often executed over multiple years. Examples of programs in BHI's 2021 Test Year include the Pole Replacement program and the Station Transformer Replacement program.

c) The Evaluation Tool calculates the Total Cost of Ownership ("TCO") for each capital program option considering monetized risks based on the total life-cycle benefit-cost streams of the option. The result is a net cost for each program alternative, where a lower value is preferred versus a higher value. BHI provides the supporting calculations utilized within the Evaluation Tool in Table 1 below.

BHI is filing a redacted version of this response on the public record in accordance with the Ontario Energy Board's Practice Direction on Confidential Filings (the "Board's Practice Direction") and the Board's Rules of Practice and Procedure. The redacted information relates to the following:

1. <u>Proprietary Information</u>

BHI has redacted certain information regarding calculations performed by the Evaluation Tool as discussed below; and is requesting that the Board allow the redacted information to remain in confidence in this proceeding.

Appendix "A" to the Practice Direction sets out the Board's considerations in determining requests for confidentiality. Among the considerations set out in that Appendix are the following:

b) whether the information consists of a trade secret or financial, commercial, scientific, or technical material that is consistently treated in a confidential manner by the person providing it to the Board.

BHI submits that the calculations performed by the Evaluation Tool represents commercial and technical material that is consistently treated in a confidential manner by the person providing it to the Board. As such it has made redactions to the remainder of its response to interrogatory 2-Staff-17 part c).

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[redacted]	[redacted]		[redacted]		[redacted]	

d) BHI provides the TCO for each alternative calculated for each capital program as listed in Table 5.4-8 in Table 3 below, with the exception of the NE Burlington TS Egress project, which was not included in the Evaluation Tool[5]. The Evaluation Tool does not provide detailed results for reliability, safety and cost benefits for each of the alternatives.

Table 3: TCO for each program alternative

Program	Program TCO ($)		
	Draft Plan (Alternative 2)	Slower Pace (Alternative 1)	Accelerated Pace (Alternative 3)
Pole Replacement Program	$27,406,848	$28,148,039	$27,369,939
Underground Rebuilds	$18,062,848	$17,998,943	$18,134,885
Circuit Breaker Replacement	$3,510,318	$3,553,346	$3,487,950
Intelligent Switches	$7,090,539	$11,490,103	$1,515,317
Upgrade Protective Relays	$2,135,061	$2,210,462	$2,080,755
Switchgear Replacement	$5,022,077	$5,471,526	$4,706,714
Station Transformer Replacement Program	$5,819,658	$5,794,582	$5,847,763
MS Feeder Cable Replacement	$13,754,331	$17,362,957	$11,419,669

[5] "Proactively Replacing Breakers, Switchgear, and Relays" were all analyzed separately in the Evaluation Tool, as shown in Table 3

2-Staff-18

Ref: Exhibit 2 – Rate Base, DSP pp. 69-70, 101, 115, 118, 126

Preamble:

BHI uses its Prioritization Tool to standardize risk assessment across a range of projects, providing an objectives-based ranking of each project's contribution to BHI's asset management (AM) objectives.

Question(s):

a) Please explain how this tool relates to the Evaluation Tool.

b) Please explain how capital projects and capital programs are defined in the Prioritization Tool. Are there any difference between capital projects/programs in Prioritization Tool and capital projects/programs in the Evaluation Tool? If so, please provide examples to explain the difference.

c) Please provide details/supporting calculations of the Prioritization Tool with examples.

d) Please explain if any changes in the 2021 total net capital expenditures (as shown in Table 5.4-9 on page 128 of the DSP) before and after the project prioritization process.

e) Are all AM objectives treated as equal or there is a weighting element? If there is a weighting element, please provide the weighting factors used for each objective.

f) Please confirm BHI defines all System Access projects as mandatory projects. Please also confirm BHI defines all System Renewal, System Service and General Plant projects as non-mandatory projects. If not confirmed, please explain how BHI defines mandatory and non-mandatory projects.

Response:

a) The ("Program") Evaluation tool assesses different alternatives within a single capital program to help determine the optimal investment levels and pacing (the "recommended program").

   The recommended program is broken down into smaller projects and combined with all other projects to develop a comprehensive list of projects. The ("Project") Prioritization Tool is used to evaluate the comprehensive list of projects against a standard set of criteria to produce a list of prioritized projects in a given year.

BHI uses the Evaluation tool in step 2 and the Prioritization tool in step 3 of its Asset Management Process, as shown in Figure 5.3-1 of the DSP.

b) Capital projects are subsets of capital programs in the Prioritization Tool. The larger capital programs are broken down into specific projects allowing BHI to assess and prioritize capital expenditures at a more granular level.

For example, Underground Rebuilds (Primary Cable) is a capital program in both the Prioritization Tool and the Evaluation Tool. This capital program is broken down into the following specific projects:

a. Brant Hills and Tyandaga South Community Cable Rebuild
b. Tyandaga North Community Primary Cable Rebuild

There is no difference between capital projects/programs in the Prioritization and Evaluation Tools.

c) The Prioritization Tool ensures that all projects are evaluated against a standard set of criteria developed based on BHI's asset management objectives. Each asset management objective is assigned a weighting, which was determined using an analytic hierarchy process ("AHP").

The criteria are evaluated based on their impact and probability of occurrence for a particular project using a standardized set of criteria tables. The Prioritization Tool has different levels of impact and probability of occurrence and a numerical value is assigned to each level of criticality. Impact values range from 0-50, and probability values range from 1 to 5.

The impact value, the probability of occurrence value, and the weighting are used to calculate a criteria score using the following equation:

$$Criteria\ Score = (Impact\ Value * Probability\ of\ Occurence\ Value) * Weighting$$

For example, the Reliability score for an underground cable replacement project could be calculated as: very high impact (50) * very likely to occur over the DSP horizon (4) * Reliability weighting (10%) = 20

Once a criteria score is calculated for each criterion, the criteria scores are accumulated to calculate the Project Priority Score.

d) Changes were made to the 2021 total net capital expenditures before the project prioritization process and as part of the project prioritization process. No changes were made to the 2021 total net capital expenditures after the project prioritization process. Please refer to BHI's response to 2-Staff-9 b) for a list of capital projects and associated capital expenditures resulting from each step of the capital expenditure planning process.

e) There is a weighting element to the AM objectives. BHI provides the weighting factors used for each objective in Table 1 below.

   Customers needs and preferences are embedded in several Asset Management objectives including customer preference, reliability, operational efficiency and safety. Customers identified reliability and operational efficiency as two of their top three priorities in Phase 1 of BHI's customer engagement activities.[1] The customer preference weighting in Table 1 below represents incremental customer support for an investment over and above the customer needs and preferences inherently included in other asset management objectives; with no regard for safety, reliability or operational effectiveness.

[1] Appendix 3.0 of Appendix 12 of the DSP

Table 1

RRFE Performance Outcome(s)	Asset Management Objective	Definition	Weight
Customer Focus	Customer Preference	Ensure the asset management plans are aligned with customer expectations and needs.	3%
Operational Effectiveness/ Financial Performance	Reliability	Ensure the asset management system provides a sustainable and reliable service to the customers.	10%
	Asset Performance	Ensure the asset management plans reduce poor performing assets and provide the opportunity to modernize the system.	7%
	Operational Efficiency	Ensure the asset management plans provide sustainable cost savings and generate new opportunities for reducing the life cycle costs of operating assets.	6%
Public Policy Responsiveness	Safety	Ensure all the assets are operated, constructed and maintained in a condition that is safe to all employees, contractors and the public.	32%
	Environmental Protection	Ensure the impacts of capital investments on sensitive environmental features are minimized.	10%
	Regulatory Compliance	Ensure the asset management plans are in regulatory compliance and legal obligations are met.	13%
All	Urgency	Ensure the asset management plans are met within a timely manner and in accordance/co-ordination with other utilities, regional planning, and 3rd party providers or with internal project dependencies.	7%
	Risk Management	Ensure Burlington Hydro effectively manages risk – financial, operational, cyber security, regulatory, obsolescence.	12%

f) BHI confirms it defines all System Access projects as mandatory projects. BHI does not define all System Renewal, System Service and General Plant projects as non-mandatory projects. An example of a mandatory General Plant project is the implementation of cyber security tool sets to comply with the Ontario Cyber Security Framework.

BHI's definition of mandatory projects includes but is not limited to those required to meet statutory and regulatory obligations found in the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*, maintain compliance with regulatory instruments that govern energy industry participants (e.g. the Distribution System Code), meet its conditions of service, and to ensure the safety of its employees, contractors, the public and its assets. BHI defines non-mandatory projects as those not meeting its definition of a mandatory project.

2-Staff-19

Ref: Exhibit 2 – Rate Base, DSP p.107

Preamble:

Table 5.4-1 shows prioritized general and reliability outcomes from Phase I of the customer engagement.

Question(s):

a) In terms of reliability outcomes, residential customers believe that “restoration time during extreme weather” is the top priority. Did BHI include any investments over the DSP period related to this customer preference versus the second ranked preference of overall length of outages? If so, please specify the project, the budgeted amount and the year.

Response:

a) Extreme weather events are often characterized by high winds and/or freezing rain and can result in significant damage to BHI’s distribution system and lengthy outages for its customers. Extreme weather events typically result in a high number of incidents in a short period of time, a higher number of incidents caused by tree contacts, and increased customer traffic to BHI’s outage map. Certain assets such as wood poles are more vulnerable to failure during extreme weather events, particularly when they exhibit signs of rot, are out of plumb / leaning, or have deteriorated remaining strength.

In order to meet customer expectations regarding restoration time during these extreme weather events, BHI invests in certain storm hardening practices in order to mitigate the impact of severe weather events. BHI also invests in technology in order to respond more effectively when severe weather does cause interruptions on its system. BHI has included a number of investments over the DSP horizon related to residential customer feedback indicating that “restoration time during extreme weather” is a priority. These investments are identified in Table 1 below.

Table 1

Project / Program	Years	Capital	OM&A	Contribution to "restoration time during extreme weather" outcome
SCADA / GIS / AMI / OMS	2021-2025	$130,000 - $195,000 per year		Modifications to BHI's OMS including integration with its SCADA system help pinpoint outage location and cause in order to triage outage response more effectively during extreme weather events.
Intelligent Switches	2021-2025	$150,000 - $200,000 per year		Automated distribution switches automatically sectionalize and isolate the section of the feeder impacted by an outage, minimizing the scope and duration of unplanned outages.
Pole replacement	2021-2025	$1,050,000 per year		Increased pacing of the replacement of poles in Poor and Very Poor condition, many of which are leaning and exhibit deteriorated remaining strength and rot, contributes to system hardening by improving asset health.
Vegetation Management	2021		$768,502	This program includes selectively removing portions of a tree canopy to reduce the “sail effect” of branches during high winds and to reduce the likelihood that broken branches will make contact with lines.

2-Staff-20

Ref: Exhibit 2 – Rate Base, DSP p.117, 118

Preamble:

Table 5.4-6 shows corporate risks and their corresponding probability of occurrence and severity impact and Table 5.4-7 shows tools and analysis for identifying risk.

Question(s):

a) Please explain how corporate risks (listed in Table 5.4-6 on page 117 of the DSP) are related to AM objectives (listed in Table 5.4-7 on page 118 of the DSP) used in the Evaluation Tool and the Prioritization Tool?

b) Do the probability of occurrence and severity potential represent the current system status?

c) How does BHI measure the extent of mitigation of these risks by programs and projects?

Response:

a) Achievement of BHI's AM objectives mitigates corporate risks. For example, managing and improving asset performance mitigates risks associated with public safety and aging infrastructure, among others. The Evaluation and Prioritization Tools are examples of how BHI implements risk management strategies to effectively identify, eliminate, and/or reduce its exposure to the identified corporate risks, which supports the achievement of BHI's AM objectives.

b) The probability of occurrence and severity potential represent the system status at the time the risk assessment is completed.

c) The extent of mitigation of risk is measured using the Evaluation and Prioritization Tools. The Evaluation Tool performs an economic evaluation of the costs and benefits – in many cases, an avoided risk such as deteriorating reliability performance – of various alternatives. The Prioritization Tool assesses projects based on their impact on each AM objective, relative to if the project was not executed. In many cases, the impact is the avoided risk of a negative reliability, safety, environmental, compliance or efficiency outcome.

2-Staff-21

Ref: Exhibit 2 – Rate Base, DSP p.123-124

Preamble:

In the Program Alternative Evaluation and Pacing subsection on page 123 of the DSP, BHI presented steps used in the Evaluation Tool. Step 3 involves assigning monetary values to the outcomes defined in Step 2.

Question(s):

a) Please explain how monetary value is assigned to each of the following factors:

   i. Safety, e.g. potential fatality or injury
   ii. Environmental protection, e.g. spilling transformer oil in drinking water source
   iii. Regulatory compliance, e.g. non-compliance with the DSC requirements
   iv. Asset performance and operational efficiency
   v. Reliability

b) Was the monetary value assigned benchmarked? If so, please provide the benchmarking study or report.

Response:

a) Monetary value was assigned to each of the following factors as follows:

   i. Safety costs are determined through industry research, subject matter expertise, and historical data where available, and are based on factors such as average cost of a utility lost-time injury.

   ii. Environmental costs are determined through industry research, subject matter expertise, and historical data where available, and are based on factors such as oil leak fines and cleanup costs.

   iii. Regulatory compliance is not directly monetized; however the Evaluation Tool allows planners to specify “other risk costs” and “other benefits” which could relate to regulatory compliance.

   iv. Asset performance costs are based on the incremental cost of reactively replacing assets and are determined through an emergency premium multiplier to the unit cost specific to each asset class.

Operational efficiency is measured in terms of productivity gains, which is a user-defined input for each alternative.

v. Reliability costs are determined through the use of the Interruption Cost Estimate ("ICE") Calculator[1]. Utility loading characteristics and historical reliability data are utilized in the calculator to produce the Weighted Event Cost and the Weighted Duration Cost, which represent a measure of the monetary losses incurred by the customer due to the interruption of electric service. These costs are used to assign a monetary value to reliability for program alternatives.

b) No, the monetary values assigned were not benchmarked.

[1] "Interruption Cost Estimate (ICE) Calculator", Nexant Inc., Lawrence Berkeley National Laboratory, 2020. URL: https://icecalculator.com/

2-Staff-22

Ref: Exhibit 2 – Rate Bas, DSP pp. 125, 128

Preamble:

Tables 5.4-8 and 5.4-9 shows 2021 prioritized capital expenditures.

Question(s):

a) Since all System Access projects are assigned as priority 1, how are they prioritized among themselves? Can BHI provide scores for each of the mandatory projects resulting from the prioritization process?

b) How does BHI ensure that each project is rated correctly by the project planners and uniformly between planners?

c) BHI mentioned there was “an unplanned, emergency transformer replacement in 2020”. What was the rating of this transformer in the ACA report?

Response:

a) BHI assigned all System Access projects a priority of 1 in the Application to indicate that they were mandatory projects and ensure they were included in the 2021 plan before discretionary projects were considered. System access projects are prioritized amongst themselves in the same manner as all other projects - the higher the capital score, the greater the impact the project has on the achievement of BHI’s asset management objectives, and the higher the priority. Please refer to page 127 of section 5.4.1(b).2 of the DSP for more information regarding project prioritization.

   BHI provides scores for each of the mandatory projects resulting from the prioritization process in Table 1 below.

Table 1

Project Name / Description	Priority Ranking	Score
Dundas St Road Widening (Walkers to Appleby) - Region	1	16
Waterdown Road Widening - City	1	29
Other Third Party Projects	1	Various
General Service - Overhead	1	40
General Service - Underground	1	41
Transformers – New Connections	1	44
Meters – New Connections	1	10
Suite Metering	1	7
Metering Infrastructure and Systems	1	Various
Subdivisions	1	28

b) BHI ensures that each project is rated correctly by the project planners by conducting prioritization tool training and providing a user manual. BHI ensures that each project is rated uniformly between planners through a risk calibration process where a review of the ratings is conducted by an independent staff member (non-project planner).

c) The rating of the unplanned, emergency transformer replacement in 2020 was Fair in the ACA report.

2-Staff-23

Ref: Exhibit 2 – Rate Base, DSP pp. 134

Preamble:

Table 5.4-10 and 5.4-11 show historical and forecasted capital and system O&M costs.

Question(s):

a) The proposed 2021 net capital expenditure is about 39% higher than the historical average (2014-2019). The proposed 2021 system O&M is about 13% higher than the historical average (2014-2019). Please discuss how BHI has considered the integration of capital vs. OM&A trade-off when preparing its 2021 budget.

Response:

a) BHI has considered the integration of capital vs. O&M trade-off as part of the capital expenditure planning process, explained in section 5.4.1 of the DSP. As part of the Program Alternatives Evaluation step, BHI develops various alternatives for non-mandatory programs, ranging from "do nothing", to partial need fulfillment, to full need fulfillment, including options for repair (primarily O&M) versus replacement (capital).

   BHI's Evaluation Tool allows planners to compare capital and O&M solutions for any number of investments and investment options. The Evaluation Tool then utilizes these inputs to calculate the total costs of ownership, total benefits and NPV for each program alternative considered.

2-Staff-24

Ref: Exhibit 2 – Rate Base, DSP p. 146

Question(s):

a) Regarding the Storm Damage project, please explain how BHI tracked spending on this project. Does BHI track spending in relation to MEDs or just a generic weather storm?

<u>Response:</u>

a) BHI tracked Storm Damage spending by setting up a separate work order to record materials, labour and vehicle costs related to restoration efforts during storms. BHI tracks spending in separate work orders when restoration costs are expected to have a significant influence on its operations, which typically aligns with MEDs but can include storms that do not meet the MED threshold.

2-Staff-25

Ref: Exhibit 2 – Rate Base, DSP p. 144

Preamble:

Table 5.4-19 shows historical and test year expenditures for System Access.

Question(s):

a) Excluding forecasted spending on the Dundas St and Waterdown Rd Road Widening programs, the proposed 2021 budget for all other projects in the System Access category represents an increase of about 15% from the historical average spending level over the 2014-2018 period. Please explain drivers for the increase.

Response:

a) The increase in the 2021 forecasted spending level from the historical average spending level over the 2014-2018 period in the System Access category, excluding Dundas St and Waterdown Rd Road Widening programs, as identified on 144-145 of the DSP, was driven by:

- **Subdivisions:** as identified through Housing Developers meetings, BHI is forecasting higher subdivision projects in 2021 to connect customers to the grid.
- **Metering Infrastructure and Systems:** higher expenditures are forecast in 2021 due to the upgrade of BHI's smart metering head end, which is at end of life and is no longer fully supported.
- **Suite Metering:** higher expenditures are forecast in 2021 due to an increase in new condominium developments driven by increased vertical growth in Burlington.
- **Other Third-Party Projects:** the expected increase in the forecasted 2021 expenditures is driven by an increase in the number of small/medium scale infrastructure programs initiated by the Region of Halton and City of Burlington.

BHI has updated its 2021 capital expenditure forecast as part of interrogatory responses, however the drivers for the increase as explained above has not changed. Please refer to 2-Staff-9 a) for further details on BHI's updated capital expenditure forecast.

2-Staff-26

Ref: Exhibit 2 – Rate Base, DSP p.174

Preamble:

Table 5.4-24 lists capital programs exceeding $180k (material threshold) and then provides Material Investment Summary Documents for these capital programs.

Question(s):

a) Please provide Material Investment Summary Documents for each of the following capital programs, which appear to be missing in the DSP.

   i. Other Third Party Projects (System Access)
   ii. Metering Infrastructure and Systems (System Access)
   iii. Other Substation Renewal (System Renewal)

Response:

a) The Other Third Party Projects, Metering Infrastructure and Systems, and Other Substation Renewal categories are each comprised of several individual projects less than $180,000. BHI grouped these projects into these three categories rather than the Miscellaneous category in order to better illustrate how capital is prioritized in BHI's proposed capital plan. BHI did not prepare Material Investment Summary Documents for these individual projects as they are all below $180,000.

2-Staff-27

Ref: Exhibit 2 - Appendix 1: 2021 Test Year Material Investment Summary Documents

Question(s):

a) Regarding the Pole Replacement program, of the poles that failed since the completion of the 2019 ACA report, how many have failed and what condition were they rated in the report?

b) Regarding the Underground Rebuilds program, why are there only two alternatives being evaluated?

c) Regarding the Station Transformer Replacement program, BHI is proposing to replace six transformers over the DSP horizon. The ACA results show that there were no station transformers were assigned to the Poor and Very Poor conditions and there were five transformers were assigned to the Fair condition. Please provide the ACA results of the six station transformers that are planned to be replaced over the DSP horizon.

d) Regarding the Intelligent Switches program, what is the assumed SAIDI benefit from the replacement of five intelligent switches over the DSP horizon?

e) Please provide information requested in the attached Excel spreadsheet regarding material investments in the System Renewal category.

f) For each of the capital project in the System Renewal category, please provide supporting calculations and explain how BHI developed the 2021 budget (i.e. what's the relationship between 2021 forecasted number of replacement and the budget?).

<u>Response:</u>

a) BHI does not track the number of wood pole failures separately from poles that are replaced on a proactive basis.

b) Only two alternatives were evaluated because these were the only two prudent alternatives identified through BHI's asset management processes. The recommended alternative was lower than the historical average investment level in this program, and due to the condition of these assets as identified in the ACA report, BHI planners were not comfortable considering a slower paced alternative.

c) The ACA results of the six station transformers that are planned to be replaced over the DSP horizon identified five in Fair condition and one in Good condition.

An asset in Fair condition has widespread significant deterioration or serious deterioration of specific components[1]. In this circumstance, diagnostic testing should be increased, and the units may need remedial work or replacement depending on their criticality[2]. BHI has increased its diagnostic testing for these transformers - Dissolved Gas Analysis ("DGA") is being conducted quarterly and for seven more transformers that are showing similar DGA results. The DGA results show elevated levels of dissolved gases that are present in the transformer's oil which indicates some internal arcing, premature aging of the internal cellulous insulation and internal overheating conditions. As a result, the condition of these assets can rapidly deteriorate to the point that they completely fail or will require immediate replacement in order to avoid catastrophic failure. These transformers are critical upstream assets; can cause catastrophic safety and environmental impacts if they fail; require up to six months of planning lead time to replace; and no more than two can be replaced in a calendar year in order to maintain system loading/balancing and backup capability. As a result, BHI does not run these assets to failure. Furthermore, BHI has 44 station transformers for which replacement must be paced to manage annual capital expenditures and customer bill impacts. Deferring one or more of the six planned replacements in 2021-2025 to the next DSP period could result in a backlog of station transformers requiring replacement. All these factors – unit condition and criticality, safety and reliability risk, system limitations, and pacing – are the bases for BHI's proposed replacement of six station transformers over the 2021 to 2025 period.

d) BHI has not determined an assumed SAIDI benefit from the replacement of five intelligent switches over the DSP horizon. However, by installing intelligent switches at the midpoint of a feeder and at the tie point between two feeders, sustained outages will typically only impact half as many customers and the duration will be reduced due to feeder segmentation. BHI is planning to install these intelligent devices at the worst performing or most critical feeders and as a result of that improvements in reliability metrics (SAIDI) are expected.

e) BHI provides the information requested in the attached Excel spreadsheet regarding material investments in the System Renewal category, filed as IR_Attachment_2-Staff-27e_BHI.

BHI is unable to provide the number of assets replaced by Health Index for 2014-2019 because it had not completed a formal ACA prior to 2019. Please refer to BHI's response to 2-SEC-19 for the total number of assets replaced from 2014-2019 in the System Renewal program (not broken out by Health Index). The assets replaced in 2020 align

[1] ACA, Table 0-1, page 7
[2] Ibid

with BHI's capital expenditure forecast; 2020 actual data is not available because BHI's year end processing is not complete.

f) Please refer to BHI's response to 2-SEC-19 for the relationship between the 2021 forecasted number of replacements and the budget in the System Renewal category.

2-Staff-28

Ref: Exhibit 2, page 126

Preamble:

BHI stated that "The number of projects identified for execution in a given year is constrained by the upper limit of the capital budget. This limit is determined by BHI Senior Management taking into account capital expenditure and depreciation levels, pacing of investments, customer engagement results, cash flow and borrowing requirements."

Question(s):

a) Regarding these statements noted above, please identify the timing of these activities in the capital expenditures planning process. Please also provide presentation material to Senior Management, if available, and any approvals in relation to setting the upper limit of the capital budget.

Response:

a) The determination of the upper limit of the capital budget is dependent on the Needs Assessment, Program Alternative Evaluation and Project Prioritization steps of the capital expenditure planning process. The pipeline of candidate investments produced as part of the Project Prioritization process is greater than the funding available to complete the projects; and is beyond the outcomes preferred by customers. BHI Senior Management establishes a threshold based on achieving the preferred outcomes, the funds available, and the risks that must be mitigated once this information is available. The upper limit of the capital budget is finalized at the Management and Board Review & Approval Stage identified in Figure 5.4-1 of the DSP.

   BHI does not have presentation material or approvals in relation to setting the upper limit of the capital budget.

2-Staff-29

Ref: Exhibit 2 - Appendix 10: 2019 Asset Condition Assessment Report

Question(s):

a) METSCO classified BHI's health index formulation as being commensurate with the stage 3 of ACA framework maturity. Was there any back testing of the ACA methodology on previous years' data to see if assets in very poor or poor condition did indeed fail, or required greater than average maintenance? If yes, please provide such analysis.

Response:

a) No, there was no back testing of the ACA methodology on previous years' data.

2-Staff-30

Ref: Exhibit 2 - Appendix 10: 2019 Asset Condition Assessment Report

Preamble:

OEB staff notes that age is a condition factor into the health index formulation for most assets in the ACA report.

Question(s):

a) For each of the following asset types, please provide rationale/explanation of the health index formulation.

- Underground Primary Conductor
- Overhead switches
- Reclosers
- Primary Switchgear
- Batteries and Chargers
- Protection Relays

Response:

a) The rationale/explanation of the health index formulation for each of these asset types can be found on the following pages of BHI's 2019 Asset Condition Assessment Report, filed as Appendix 10 of the DSP:

- Underground Primary Conductor (page 39-41)
- Overhead switches (page 52-54)
- Reclosers (page 55-56)
- Primary Switchgear (63-64)
- Batteries and Chargers (68-70)
- Protection Relays (71-73)

2-Staff-31

Ref: Exhibit 2 – 2.1.3.1 Calculation of Cost of Power
Chapter 2 appendices – 2-ZA and 2-ZB

Preamble:

BHI used the commodity prices from the Regulated Price Plan Report – November 1, 2020 to October 31, 2021, issued on October 13, 2020 to complete appendix 2-ZA. The OEB issued new Regulated Price Plan prices effective January 1, 2021 on December 15, 2020.[1]

Question(s):

a) Please update appendix 2-ZA with the new commodity prices.

b) Please use the updated Ontario Electricity Rebate value of 21.2% in appendix 2-ZB.

Response:

a) BHI attaches Appendix 2-ZA with the new commodity prices as Attachment_2Z_OEB_Chapter2Appendices_BHI_Revised.

b) BHI attaches Appendix 2-ZB with the new Ontario Electricity Rebate value of 21.2% as Attachment_2Z_OEB_Chapter2Appendices_BHI_Revised.

[1] https://www.oeb.ca/sites/default/files/letter-new-rpp-prices-20201215.pdf

2-Staff-32

Asset Disposals
Ref: Exhibit 2, Page 43, Section 2.1.2.4

Preamble:

BHI states that:

BHI has identified its asset disposals in its Fixed Asset Continuity Schedules for each of the historical, bridge and test years. Some of these amounts relate to gains and losses on disposals as a result of the transition to IFRS and have been included in USoA Account 1575, IFRS-CGAAP Transitional PP&E Amounts. The amounts that specifically relate to USoA Account 1575 are disposals associated with the retirement of a pool of like assets. These dispositions are recorded under MIFRS and not under CGAAP. BHI provides a reconciliation of the gains or losses on disposals in its Fixed Asset Continuity Schedules to the gains or losses on disposals attributable to the transition to IFRS, and recorded in USoA Account 1575, in Table 32 below.

OEB staff has reproduced Table 32 as below:

Table 32 – Gains or Losses on Disposals: Account 1575

Year	Total Fixed Asset Continuity Schedule			Recorded under MIFRS and not under Revised CGAAP (1575 Entry)			Recorded under MIFRS and Revised CGAAP		
	Gross Assets	Accum Deprn	Loss/(Gain) on Disposal	Gross Assets	Accum Deprn	Loss/(Gain) on Disposal	Gross Assets	Accum Deprn	Loss/(Gain) on Disposal
2014	($4,098)	$4,098	$0				($4,098)	$4,098	$0
2015 (2014 Disposals)[1]	($1,040,628)	$588,601	$452,027	($181,703)	$99,252	$82,451	($732,381)	$418,653	$313,728
2015				($126,544)	$70,697	$55,848			
2016	($450,984)	$417,963	$33,021	($61,953)	$28,932	$33,021	($389,031)	$389,031	$0
2017	($184,202)	$140,781	$43,421	($80,067)	$58,667	$21,400	($104,135)	$82,114	$22,021
2018	($1,201,456)	$859,038	$342,418	($751,471)	$419,336	$332,135	($449,985)	$439,702	$10,283
2019	($598,896)	$481,886	$117,010	($192,142)	$121,880	$70,262	($406,754)	$360,006	$46,748
2020 Bridge Year	($382,456)	$256,787	$125,669	($382,456)	$256,787	$125,669	$0	$0	$0
2021 Test Year	($382,456)	$256,787	$125,669	($84,207)	$56,538	$27,669	($298,249)	$200,249	$98,000

Question(s):

a) Please provide the USoAs for the assets with disposals recorded in Account 1575.

b) Please reconcile the gross assets, accumulated depreciation and loss on disposal for the above assets on the fixed asset continuity schedule for all years to the summary figures provided in the Table 32 above and explain any discrepancies, if applicable.

c) Please provide the actual disposal figures for 2020.

d) Please confirm OEB staff's observation that 2021 disposals are forecasted to be the same as the 2020 disposals.

i. If confirmed, please explain why the asset disposal figures in Account 1575 in 2021 are different than the ones in 2020.

Response:

a) Table 1 provides the USoAs for the assets with disposals in Account 1575.

Table 1

OEB Account	Description	2015 (2014 Disposals)	2015	2016	2017	2018	2019	2020	2021
1830	Poles, Towers, and Fixtures	$ 4,023	$ 10,352	$ 3,110	$ 1,414	$ 6,024	$ -	$ -	$ -
1835	OH Conductors and Devices	$ 5,295	$ 5,495	$ 5,661	$ 2,367	$ 3,049	$ -	$ -	$ -
1840	UG Conduit	$ 475	$ 471	$ -	$ -	$ -	$ -	$ -	$ -
1845	UG Conductors and Devices	$ 536	$ 221	$ 2,403	$ -	$ 139	$ -	$ -	$ -
1850	Line Transformers	$ 69,871	$ 38,842	$ 20,246	$ 17,619	$ 31,423	$ 32,170	$ 33,517	$ 7,380
1855	Services	$ 2,251	$ 467	$ 1,601	$ -	$ -	$ -	$ -	$ -
1860	Meters	$ -	$ -	$ -	$ -	$ 291,501	$ 38,092	$ 92,152	$ 20,289
	Loss on Disposal - Entry to 1575	**$ 82,451**	**$ 55,848**	**$ 33,021**	**$ 21,400**	**$ 332,135**	**$ 70,262**	**$ 125,669**	**$ 27,669**

b) Table 2 reconciles the gross assets, accumulated depreciation and loss on disposal for the assets in Table 1 from the fixed asset continuity schedule to the summary figures provided in Table 32, Exhibit 2 of BHI's Application.

Table 2

OEB Account	Year	Total Fixed Asset Continuity Schedule			Recorded under MIFRS and not under Revised CGAAP (1575 Entry)			Recorded under MIFRS and Revised CGAAP		
		Gross Assets	Accum Deprn	Loss/(Gain) on Disposal	Gross Assets	Accum Deprn	Loss/(Gain) on Disposal	Gross Assets	Accum Deprn	Loss/(Gain) on Disposal
	2015 (2014 Disposals)[1]	($569,202)	$228,084	$341,118	($181,703)	$99,252	$82,451	($260,955)	$58,136	$202,819 [2]
1830	Poles, Towers, and Fixtures	($8,808)	$4,785	$4,023						
1835	OH Conductors and Devices	($8,413)	$3,118	$5,295						
1840	UG Conduit	($1,343)	$869	$475						
1845	UG Conductors and Devices	($828)	$291	$536						
1850	Line Transformers	($159,283)	$89,412	$69,871						
1855	Services	($3,027)	$777	$2,251						
	2015				($126,544)	$70,697	$55,848			
1830	Poles, Towers, and Fixtures	($25,764)	$15,411	$10,352						
1835	OH Conductors and Devices	($12,811)	$7,317	$5,495						
1840	UG Conduit	($1,378)	$907	$471						
1845	UG Conductors and Devices	($402)	$181	$221						
1850	Line Transformers	($84,640)	$45,798	$38,842						
1855	Services	($1,549)	$1,082	$467						
	2016	($61,952)	$140,753	($78,801)	($61,952)	$28,932	$33,021	$	$111,821	($111,822) [3]
1830	Poles, Towers, and Fixtures	($5,826)	$2,715	$3,110						
1835	OH Conductors and Devices	($9,196)	$3,535	$5,661						
1845	UG Conductors and Devices	($2,716)	$314	$2,403						
1850	Line Transformers	($42,586)	$22,340	$20,246						
1855	Services	($1,628)	$27	$1,601						
	2017	($81,327)	$59,201	$22,126	($80,067)	$58,667	$21,400	($1,260)	$534	$726 [4]
1830	Poles, Towers, and Fixtures	($3,509)	$2,095	$1,414						
1835	OH Conductors and Devices	($6,332)	$3,965	$2,367						
1850	Line Transformers	($70,226)	$52,607	$17,619						
	2018	($757,801)	$421,817	$335,984	($751,471)	$419,336	$332,135	($6,330)	$2,481	$3,849 [4]
1830	Poles, Towers, and Fixtures	($10,930)	$4,906	$6,024						
1835	OH Conductors and Devices	($5,708)	$2,659	$3,049						
1845	UG Conductors and Devices	($232)	$93	$139						
1850	Line Transformers	($84,673)	$53,250	$31,423						
1860	Meters	($649,928)	$358,427	$291,501						
	2019	($192,142)	$121,880	$70,262	($192,142)	$121,880	$70,262	($)	($)	$
1850	Line Transformers	($97,446)	$65,275	$32,170						
1860	Meters	($94,696)	$56,604	$38,092						
	2020 Bridge Year	($382,456)	$256,787	$125,669	($382,456)	$256,787	$125,669	($)	$	$
1850	Line Transformers	($94,901)	$61,384	$33,517						
1860	Meters	($287,555)	$195,403	$92,152						
	2021 Test Year	($382,456)	$256,787	$125,669	($84,207)	$56,538	$27,669	($298,249)	$200,249	$98,000 [5]
1850	Line Transformers	($94,901)	$61,384	$33,517						
1860	Meters	($287,555)	$195,403	$92,152						

1. 2014 Loss on Disposals for pooled assets recorded to Retained Earnings (prior period adjustment); 2014 Gross Asset and Accumulated Depreciation entries for disposals on pooled assets recorded in 2015 FA continuites.

2. IFRS Transition adjustments

3. Adjustment to Contributed Capital Amortization journal entry booked in 2015 to incorrect GLs on transition to IFRS.

4. Disposal of specific assets either from a MVA or elimination of LTLT's.

4. Refer to IRR Staff-72c

c) 2020 actual data is not available because BHI's year end processing is not complete.

d) BHI confirms OEB staff's observation that 2021 disposals are forecasted to be the same as the 2020 disposals.

   i. The asset figures in Account 1575 for 2021 are different than the ones in 2020 because BHI is only recording 4 months activity in Account 1575 for 2021. (January 1 to April 30). Please refer to BHI's response to 9-Staff-72 c).

2-Staff-33

Opening Net Book Values of the ICM Assets
Ref 1: Attachment 2 Chapter 2 Appendices, Tab Appendix 2-BA Fixed Assets Continuity Schedule
Ref 2: Exhibit 2, pages 81 and 83
Ref 3: BHI's 2019 IRM Decision and Order EB-2018-0021, Page 23

Preamble:

On the 2021 Fixed Asset Continuity Schedule, BHI includes the net book value of $2,461,000 (comprised of costs of $2,568,000 and accumulated depreciation of $(107,000)) for the two ICM assets that were approved in its 2019 IRM proceeding.[1]

In Exhibit 2, BHI proposes to incorporate $544,333 for the Tremaine TS CCRA project in 2021 opening rate base and the details of the cost and accumulated deprecation are provided in Table 81, reproduced below:

Table 81 – Actual/Expected Amounts Recorded - Tremaine TS CCRA true-up

Accounts	2019	2020	Cumulative 2020	2021	Total
1508 - Incremental Capital Expenditures	$568,000	$0	**$568,000**	$0	**$568,000**
1508 - Depreciation Expense	$4,733	$9,467	**$14,200**	$9,467	**$23,667**
1508 - Accumulated Depreciation	($4,733)	($14,200)	**($14,200)**	($23,667)	**($23,667)**
1508 - Incremental Capital Expenditures - Carrying Charges	$364	$1,043	**$1,407**	$160	**$1,567**
1508 - Rate Rider Revenues - Carrying Charges	($806)	($3,000)	**($3,806)**	($488)	**($4,295)**
Addition to Opening Rate Base - 2021 Test Year					**$544,333**

BHI proposes to incorporate $1,916,667 for the Tremaine TS additional breakers in the 2021 opening rate base and the details of the cost and accumulated deprecation are provided in Table 84, reproduced below:

Table 84 – Actual/Expected Amounts recorded for Tremaine TS Additional Breakers CCRA

Accounts	2019	2020	Cumulative 2020	2021	Total
1508 - Incremental Capital Expenditures	$2,000,000	$0	**$2,000,000**	$0	**$2,000,000**
1508 - Depreciation Expense	$16,667	$33,333	**$50,000**	$33,333	**$83,333**
1508 - Accumulated Depreciation	($16,667)	($50,000)	**($50,000)**	($83,333)	**($83,333)**
1508 - Incremental Capital Expenditures - Carrying Charges	$0	$819	**$819**	$342	**$1,161**
1508 - Rate Rider Revenues - Carrying Charges	$0	($624)	**($624)**	($310)	**($933)**
Addition to Opening Rate Base - 2021 Test Year					**$1,916,667**

Page 23 of BHI's 2019 IRM Decision and Order states that:

[1] EB-2018-0021.

> The OEB approves the use of full-year inputs in the ICM funding calculations for the two ICM projects approved in this Decision.
>
> The OEB relies upon the best information available, acknowledging that Burlington Hydro has applied to defer rebasing until 2021. Burlington Hydro's deferral request has yet to be decided. If the deferral request is approved, 2021 would be the rebasing year and the full-year rule would apply. If the request is not approved, 2020 would be the rebasing year and the half-year rule would apply.

OEB staff notes that BHI's request to defer rebasing from 2020 to 2021 was approved.

Question(s):

a) Please confirm that BHI has applied the half-year rule for depreciation in 2019 for both ICM projects in calculating the opening net book values of the ICM assets. If so, please provide rationale, given the OEB's findings in the 2019 IRM Decision and Order.

b) Please provide the opening net book values for the two ICM projects, when applying the full year depreciation amount in 2019.

c) Please calculate the rate impact between the half-year depreciation approach used by BHI and the full-year depreciation approach.

Response:

a) BHI confirms that it has applied the half-year rule for the purposes of calculating depreciation expense in 2019 for both ICM projects.

   When BHI calculated the ICM funding and corresponding rate riders for these two ICM projects, it applied the full-year depreciation approach but erroneously applied the half-year depreciation approach to calculate the opening net book value for 2021.

b) The opening net book value for both ICM projects when applying the full year depreciation amount in 2019 is as follows:
   i. ICM Project 1 – Tremaine TS CCRA - $549,067 (as compared to $533,800 using the half-year rule)
   ii. ICM Project 2 – Tremaine TS Additional Breakers CCRA - $1,933,333 (as compared to $1,950,000 using the half-year rule)

c) BHI has calculated the rate base impact between the half-year depreciation approach and the full-year depreciation approach as follows:
   i. ICM Project 1 – Tremaine TS CCRA – opening 2021 rate base is $4,733 lower using the full-year depreciation approach
   ii. ICM Project 2–- Tremaine TS Additional Breakers CCRA – opening 2021 rate base is $16,667 lower using the full-year depreciation approach

2-Staff-34

Amortization of Deferred Revenues USoA 2440
Ref 1: Accounting Procedures Handbook (APH), page 102
Ref 2: Attachment 2 Chapter 2 Appendices, Tab 2-BA Fixed Assets Continuity schedule and Tab 2-H Other Revenues
Ref 3: Attachment 3_2C Depreciation Expenses

Preamble:

Page 102 of the APH defines the deferred revenue USoA 2440 and states that:

Amounts recognized in this account should be amortized to income over the useful life of the related property, plant and equipment by debiting this account and crediting Account 4245, Government and Other Assistance Directly Credited to Income.

OEB staff notes that USoA 4245 is one of the USoAs in the Appendix 2-H Other Revenues.

Per review of Appendix 2-BA, Appendix C and Appendix 2-H, OEB staff notes that the amortization of the deferred revenues 2440 is netted against the depreciation expense in the Appendix 2-C. However, per the APH, the amortization of the USoA 2440 should be recorded in the USoA 4245 which is one component of the other revenues.

Question(s):

a) Please confirm OEB staff's observation.

b) If confirmed, please update the relevant schedules.

<u>Response:</u>

a) BHI confirms OEB Staff's observation.
b) BHI attaches the updated Appendix 2-BA and Appendix 2-H schedules as:
    - Attachment_Main_OEB_Chapter2Appendices_BHI_Revised

   BHI attaches the updated Appendix 2-C schedule as:
    - Attachment_2C_OEB_Chapter2Appendices_BHI_Revised

3-Staff-35

Load Forecast
Ref: Exhibit 1, page 81

Preamble:

BHI states that it "intends to update its load forecast - before a decision is rendered on this Application – once full 2020 data is available and may consider adjustments at that time if they are material."

Question(s):

a) Is BHI ready to make an update to its forecast with its responses to these interrogatories?

b) If BHI is not ready to make an update to its load forecast at this time, can it advise whether it still expects to make an update, and if so, when that update would be provided?

Response:

a) No, BHI is not ready to make an update to its load forecast in response to these interrogatories.

b) BHI is not planning to update its load forecast. Full year 2020 data is not yet available. BHI thought at the time it filed its Application – and prior to receiving Procedural Order No. 1 – that the Application timeline would allow for an update to incorporate 2020 data, however it does not.

   BHI did make an update to its load forecast to correct for the following:

   - The Scotiabank forecast FTE growth rate for 2021 in the Application was -6%. This was an error and has been corrected in these interrogatories;
   - The pre-COVID 2020 FTE growth rate was applied to both 2020 and 2021 for the residential rate class in the Application. This was an error (please refer to BHI's responses to 3-Staff-37 and 3.0-VECC-32) and has been corrected in these interrogatories;
   - The 2019 and 2020 FTE growth rates (with-COVID) were applied for the years 2020 and 2021. This was an error (please refer to BHI's responses to 3-Staff-37 and 3.0-VECC-34) and has been corrected in these interrogatories.

   Please refer to BHI's response to 1-Staff-1 for the attachments filed in relation to the above corrections.

3-Staff-36

Energy Forecast
Ref: Exhibit 3, page 9, 18, 24, 30,
Ref Load Forecast Model, Monthly Data (to June 2020)

Preamble:

BHI used monthly consumption per customer per day as the dependent variable in the regression models all weather sensitive rate classes. In each case, it indicates that the number of customers and number of month days were found to be statistically significant variables.

As measures of economic activity, BHI has used Ontario FTEs to forecast Residential energy consumption, Toronto FTEs to forecast General Service < 50 kW energy consumption, and GDP to forecast General Service > 50 kW energy consumption.

Question(s):

a) For each of Residential, GS < 50, and GS > 50, please provide the regression statistics and resulting 2021 energy forecast where total class consumption is used as the dependent variable, and number of customers and number of days in the month are used as explanatory variables.

b) Please explain how each measure was selected for each rate class.

c) If BHI has used different measures of economic activity in each rate class because the different measures are most strongly correlated with energy use in each rate class, please explain why BHI believes this to be the case.

d) If BHI has not used the measure most strongly correlated with energy use, please explain why.

Response:

a) BHI provides the regression statistics and 2021 forecast summary results where total class consumption is used as the dependent variable, and number of customers and number of days in the month are used as explanatory variables Tables 1 – 4 below. The results are attached as IR_Attachment_3-Staff-36_BHI.

Table 1 - Residential Regression Statistics

Model 1: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: Res_NoCDM
rho = 0.293976

	coefficient	std. error	t-ratio	p-value
const	-30249890.8	70762388.478	-0.427	0.66985
HDD12	14443.6	1439.211	10.036	0.00000
CDD14	70695.8	2818.582	25.082	0.00000
Trend	-40781.7	45170.402	-0.903	0.36855
Ont_FTEAdj	7093.1	3758.984	1.887	0.06175
Shoulder	-2281728.1	389905.660	-5.852	0.00000
Residential_Customers	-457.2	1134.668	-0.403	0.687781
MonthDays	1654793.7	146368.805	11.306	3.11E-20

Statistics based on the rho-differenced data

Mean dependent var	45847346.96	S.D. dependent var	6849376.767
Sum squared resid	2.468E+14	S.E. of regression	1.48E+06
R-squared	0.955858515	Adjusted R-squared	9.53E-01
F(7, 112)	265.7407821	P-value(F)	1.15E-66
rho	-0.00131468	Durbin-Watson	1.989367026

Table 2 - GS<50 kW Regression Statistics

Model 4: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: GS_lt_50_NoCDM
rho = 0.181521

	coefficient	std. error	t-ratio	p-value
const	-27557429.1	4612302.332	-5.975	0.00000
HDD12	4981.4	199.536	24.965	0.00000
CDD16	13515.1	520.870	25.947	0.00000
Trend	-23176.8	5036.019	-4.602	0.00001
Tor_FTEAdj	1761.7	675.686	2.607	0.01037
Shoulder	-215549.9	58750.513	-3.669	0.00037
GS_lt_50_Customers	4991.0	820.483	6.083	1.68E-08
MonthDays	351307.7	23755.797	14.788	4.29E-28

Statistics based on the rho-differenced data

Mean dependent var	14813807	S.D. dependent var	1037764.0
Sum squared resid	5693584781108	S.E. of regression	225467.5
R-squared	0.95561	Adjusted R-squared	0.95284
F(7, 112)	330.9659473	P-value(F)	1.02E-71
rho	-0.019620339	Durbin-Watson	2.014823848

Table 3 - GS>50 kW Regression Statistics

Model 5: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: GS_gt_50_NoCDM
rho = 0.361454

	coefficient	std. error	t-ratio	p-value
const	-65109283	24356960.486	-2.673	0.0086
HDD14	14180	954.478	14.856	0.0000
CDD14	48267	1666.247	28.967	0.0000
GDP	41	31.421	1.315	0.1913
Trend	-49468	39662.012	-1.247	0.2149
Dec	-3192226	424155.723	-7.526	0.0000
GS_gt_50_Customers	51972	8777.853	5.921	3.58E-08
MonthDays	1922313	101458.477	18.947	1.00E-36

Statistics based on the rho-differenced data

Mean dependent var	76577517	S.D. dependent var	4216837.47
Sum squared resid	128632445021440	S.E. of regression	1071682.78
R-squared	0.93921	Adjusted R-squared	0.93541
F(7, 112)	282.68408	P-value(F)	4.39E-68
rho	-0.04808	Durbin-Watson	2.084472388

Table 4 – CDM Adjusted 2021 Load Forecast

kWh	2021 Weather Normal Forecast	CDM Adjustment	2021 CDM Adjusted Forecast
Residential	524,672,223	14,135	524,658,088
GS < 50	170,400,465	597,270	169,803,195
GS > 50	851,986,611	6,157,956	845,828,655
Street Light	5,569,644		5,569,644
USL	3,103,371		3,103,371
Total	1,555,732,313	6,769,360	1,548,962,953

b) The Residential regression uses HDD12, CDD14, Trend, Adjusted Ontario FTEs, and the Shoulder Variable. The HDD and CDD variables were selected as those variables were the most statistically significant among the range of degree day variables considered, as demonstrated in Exhibit 3, Page 17 (Figure 1). A trend variable was considered because average consumption per Residential customer (with CDM added back) declined by 0.77% per year from 2010 to 2019 and the variable was found to be statistically significant. Adjusted Ontario FTEs was found to be a statistically significant variable, with a higher t-statistic than alternate economic variables. The Adjusted R-squared for the model was also higher when Adjusted Ontario FTEs was used than alternate economic variables. Consumption was found to be lower in the spring in fall months beyond what is explained by the degree day variables so the Shoulder variable was considered and found to be statistically significant.

The GS<50 kW regression uses HDD12, CDD16, Trend, Adjusted Toronto FTEs, and the Shoulder Variable. The HDD and CDD variables were selected as those variables were the most statistically significant among the range of degree day variables considered, as demonstrated in Exhibit 3, Page 23 (Figure 4). A trend variable was considered because average consumption per GS<50 kW customer (with CDM added back) declined by 0.32% per year from 2010 to 2019 and the variable was found to be statistically significant. Adjusted Toronto FTEs was found to be a statistically significant variable, with a higher t-statistic than alternate economic variables. The Adjusted R-squared for the model was also higher when Adjusted Toronto FTEs was used than alternate economic variables. Consumption was found to be lower in the spring in fall months beyond what is explained by the degree day variables so the Shoulder variable was considered and found to be statistically significant.

The GS>50 kW regression uses HDD14, CDD14, Trend, GDP, and a December binary variable. The HDD and CDD variables were selected as those variables were the most statistically significant among the range of degree day variables considered, as demonstrated in Exhibit 3, Page 29 (Figure 7). A trend variable was considered because average consumption per GS>50 kW customer (with CDM added back) declined by

0.07% per year from 2010 to 2019 and the variable was found to be statistically significant. GDP was found to be a statistically significant variable, with a higher t-statistic than alternate economic variables. The Adjusted R-squared for the model was higher when GDP and the trend variable were included and the annual mean absolute percentage error was lower when these variables were included. Consumption was found to be lower in December beyond what is explained by the HDD variable so the December binary variable was considered and found to be statistically significant.

c) BHI confirms it has used different measures of economic activity in each rate class because different classes are more strongly correlated with different economic measures. BHI expects this is due to the composition of businesses within each of the general service rate classes.

Statistics Canada does not track economic data for the City of Burlington so measures from Toronto and Ontario are used as approximations. Larger businesses within the GS>50 kW rate class are more likely to interact with other business and customers across Ontario so its consumption is more aligned with the economic conditions of the province as a whole. Additionally, GS>50 kW rate class customers are more capital-intensive so consumption is less dependent on the number of employees.

Smaller businesses within the GS<50kW rate class typically deal with customers more local customers so economic measures from Toronto prove to be more aligned than Ontario-wide measures.

GDP data is provided by Statistics Canada on an annual basis and FTE data is available on a monthly basis. As a result, FTE measures allow within-year economic impacts to be reflected in the predicted data.

Economic data from Hamilton was also considered but found not to be statistically significant, which is likely because Burlington's economic diversity is more aligned to Toronto or Ontario as a whole than Hamilton, which is disproportionately in the manufacturing sector.

d) BHI has used the economic measure most strongly correlation with consumption for each class.

3-Staff-37

Energy Forecast
Ref: Exhibit 3, page 15
Ref Load Forecast Model, sheet Res Normalized Monthly Average; sheet Economic 2020 Adj

Preamble:

With respect to COVID-19, BHI indicates that it “intends to update the load forecast - before a decision is rendered on this Application - once full 2020 data is available; and may consider manual adjustments at that time if these direct impacts persist.” It states that it performed manual adjustments to forecast consumption from July 2020 to December 2020, but that “the manual adjustments do not persist to the 2021 Test Year forecast.

A comment in sheet Economic (2020 Adj.) cell K28 states “Data in this sheet is used to forecast July 2020 to Dec 2020 Consumption only. It does not Impact the test year forecast.”

OEB staff notes that the Res Normalized Monthly Avg worksheet refers to column X (labelled Ont_FTEAdj) of the Economic 2020 Adj sheet for all months from January 2020 to December 2021. Further, the formulas in column X of worksheet Economic 2020 Adj for January 2020 to December 2021 reference the economic variable from one year prior and inflate it by a Feb 12, 2020 BMO forecast of the 2020 FTE growth rate of 1.9%.

In the GS < 50 Normalized Monthly Avg worksheet, OEB staff notes that the economic indicator used is the TorFTEAdj, column F of the Economic 2020 Adj for all months of 2021. For each month, this is calculated as the corresponding month two-years prior, adjusted to increase by the 2019 and 2020 average growth in cells R7 and R8 respectively.

For both General Service < 50 kW and General Service > 50 kW, the applicable growth rates are forecasted on the basis of an average of forecasts from four major banks. These are BMO (June 11, 2020), TD (July 17, 2020), Scotia Bank (August 4, 2020), and RBC (June 10, 2020).

For each rate class, the economic variable and the trend variable exhibit an increasing trend over time. While the economic variable has a positive co-efficient, the trend variable has a negative coefficient.

Question(s):

a) Please confirm that the data in the Economic (2020 Adj.) worksheet is actually used.

b) Please explain why, in the Residential rate class, the 2020 FTE growth rate was used for both 2020 and 2021.

c) Please explain why the No Covid scenario was used for the residential rate class in forecasting 2021.

d) Please explain why the 2019 and 2020 growth rates were used to forecast to 2021 relative to 2019 when the applicable growth rates would have been 2020 and 2021.

e) For each of the residential, general service < 50 kW and general service > 50 kW, have the economic variables and trend variable been tested for colinear independence? If not, please do so.

f) Please provide the results of the tests for colinear independence between the economic variables and the trend variable.

g) As a scenario, please provide a regression for each rate class where a trend variable is not used.

h) Please update the bank forecasts to the most recent available information.

Response:

a) BHI confirms that the data in the Economic (2020 Adj.) worksheet is used.

b) The 2020 FTE growth rate was used in error for 2021. This error has been corrected in the revised load forecast filed as:
Attachment_Load_Forecast_Model_BHI_Revised

c) The short-term economic impact resulting from the COVID-19 pandemic, namely the 5.1% decrease in FTEs, does not reflect the impact that COVID-19 had on residential consumption. Conversely, the impact of the pandemic resulted in increased residential consumption, which may persist beyond the pandemic as more FTEs work from home. Burlington Hydro does not expect residential consumption to decline as a result of the pandemic so the non-COVID scenario, the forecast prior to the pandemic, was used to forecast residential consumption in 2020 and 2021.

d) The 2019 growth rate was used in error. The revised load forecast uses the 2020 and 2021growth rates. The revised load forecast is filed as:

Attachment_Load_Forecast_Model_BHI_Revised

e) For each of the residential, general service < 50 kW and general service > 50 kW, the economic variables and trend variable have not been tested for colinear independence. Please refer to part f) below.

f) BHI provides the results of the tests for collinear independence between the economic variables and the trend variable below.

Residential
corr(Trend, GDP) = 0.99019420
Under the null hypothesis of no correlation:
t(118) = 76.9967, with two-tailed p-value 0.0000

GS<50 kW
corr(Ont_FTEAdj, Trend) = 0.98231934
Under the null hypothesis of no correlation:
t(118) = 56.9977, with two-tailed p-value 0.0000

GS<50 kW
corr(Tor_FTEAdj, Trend) = 0.98080421
Under the null hypothesis of no correlation:
t(118) = 54.6386, with two-tailed p-value 0.0000

g) BHI provides regressions for each rate class where a trend variable is not used in IR_Attachment_3-Staff-37_BHI. The regression statistics from this scenario are provided in Tables 1 to 3 below. Note that, since consumption per customer is declining, the coefficient of the economic variables for the Residential and GS<50kW classes is negative.

Table 1 - Residential Regression Statistics

Model 26: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: AvgResD
rho = 0.366564

	coefficient	std. error	t-ratio	p-value
const	32.27178	3.04032	10.61461	0.00000
HDD12	0.00778	0.00080	9.79092	0.00000
CDD14	0.03844	0.00151	25.42676	0.00000
Ont_FTEAdj	-0.00153	0.00044	-3.49430	0.00068
Shoulder	-1.20245	0.20476	-5.87260	0.00000

Statistics based on the rho-differenced data

Mean dependent var	25.1885	S.D. dependent var	3.583059
Sum squared resid	77.55991	S.E. of regression	0.821239
R-squared	0.94929	Adjusted R-squared	0.947526
F(4, 115)	384.8832	P-value(F)	1.42E-65
rho	-0.03079	Durbin-Watson	2.03E+00

Table 2 - GS<50 kW Regression Statistics

Model 27: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: AvgGSlt50D
rho = 0.310908

	coefficient	std. error	t-ratio	p-value
const	100.97588	3.82950	26.36789	0.00000
HDD12	0.03028	0.00155	19.48236	0.00000
CDD16	0.07793	0.00389	20.04972	0.00000
Tor_FTEAdj	-0.00510	0.00120	-4.23358	0.00005
Shoulder	-2.01740	0.42883	-4.70445	0.00001

Statistics based on the rho-differenced data

Mean dependent var	93.04018485	S.D. dependent var	6.1102397
Sum squared resid	346.47536	S.E. of regression	1.73575
R-squared	0.92278	Adjusted R-squared	0.92010
F(4, 115)	338.66113	P-value(F)	0.00000
rho	-0.02002	Durbin-Watson	2.02135

Table 3 - GS>50 kW Regression Statistics

Model 28: Prais-Winsten, using observations 2010:01-2019:12 (T = 120)
Dependent variable: AvgGSgt50MD
rho = 0.278203

	coefficient	std. error	t-ratio	p-value
const	2234.9185	84.3354	26.5003	0.0000
HDD14	0.4857	0.0326	14.9083	0.0000
CDD14	1.5560	0.0652	23.8541	0.0000
GDP	0.0001	0.0001	0.8188	0.4146
Dec	-128.9208	13.9065	-9.2705	0.0000

Statistics based on the rho-differenced data

Mean dependent var	2505.586848	S.D. dependent var	1.25E+02
Sum squared resid	216819.95136	S.E. of regression	43.42109
R-squared	0.88312	Adjusted R-squared	0.87905
F(4, 115)	222.22451	P-value(F)	0.00000
rho	-0.01154	Durbin-Watson	2.01036

h) The latest bank forecasts are provided in the Table 4 below. Please note that the Scotiabank 2021 FTE forecast growth rate was entered as -6% in the load forecast filed in the Application on October 30, 2020; but should have been 6%. This has been corrected in the revised load forecast.

Table 4

	BMO	TD	Scotia	RBC	Average
Report Date	23-Dec-20	15-Dec-20	12-Jan-21	15-Dec-20	
FTE					
2019	2.90%		2.90%	2.90%	2.90%
2020	(5.10%)	(5.00%)	(5.00%)	(4.90%)	(5.00%)
2021	5.10%	5.70%	3.90%	5.80%	5.13%
GDP	23-Dec-20	15-Dec-20	12-Jan-21	15-Dec-20	
2019	2.10%		2.10%	2.10%	2.10%
2020	(5.60%)	(6.20%)	(5.60%)	(5.60%)	(5.75%)
2021	5.10%	5.60%	4.70%	5.50%	5.23%

3-Staff-38

Customer Connections
Ref: Exhibit 3, page 28
Ref Load Forecast Model, Monthly Data (to June 2020)

Preamble:

BHI indicates that 40 customers were reclassified from the GS < 50 kW to the GS < 50 kW customer classes in November 2019. As a result, the GS > 50 customer count increased from 980 to 1,020. Subsequently the customer count decreased to 1,006 in January 2020 and 996 the following month.

With respect to GS < 50 kW, BHI also states that it “intends to make an adjustment to the customer counts for the 2020 reclassification before the OEB renders a decision on this application.”

Question(s):

a) Is BHI ready to make the adjustment to customer counts for the 2020 reclassification? If so, please provide the adjustment and any reasons for the changes. If not, please provide an update on when BHI believes this information will be available.

b) Please explain the cause of the subsequent decrease in customer connections.

c) Please provide customer connections for all rate classes as of the most recent month available.

<u>Response:</u>

a) Please refer to BHI’s response to 3-Staff-35.

b) The 996 in February of 2020 is an error – the correct customer count is 1008. BHI did not have time to correct for this error in the revised load forecast filed in response to these interrogatories as Attachment_Load_Forecast_Model_BHI_Revised. The impact is an increase in the GS>50 kW customer count of less than 1.

c) BHI provides customer/device counts at the end of December 2020 in Table 1 below.

Table 1

Class	Customer / Device Count
Residential	61,803
GS < 50	5,560
GS > 50	984
Street Light	17,186
USL	557

3-Staff-39

CDM Adjustment

Ref: Exhibit 3, page 47

Preamble:

Table 28 identified the proposed forecast of the CDM adjustment based on a half-year of savings from 2019, and a full year of savings from 2020 persisting into 2021.

Table 28 –Forecasted kWh Savings by Rate Class

Rate Class	2019			2020	2021	CDM Adj.	LRAMVA Target
	kWh	Weight	Amount	kWh	kWh	kWh	kWh
	A	B	C = A * B	D	E	F = C + D	G = A + D
Residential	28,270	0.5	14,135	0	0	14,135	28,270
GS<50 kW	955,494	0.5	477,747	119,523	0	597,270	1,075,017
GS>50 kW	7,335,111	0.5	3,667,556	2,490,400	0	6,157,956	9,825,511
TOTAL	**8,318,875**	**0.5**	**4,159,438**	**2,609,923**	**0**	**6,769,360**	**10,928,798**

Question(s):

a) For 2019 residential savings, please confirm that 28,270 kWh refers to actual savings from the Swimming Pool Efficiency Program.

b) Please confirm that the GS<50 kW and GS>50 kW rate class savings in 2019 and 2020 are part of the Conservation First Framework (CFF). If so, please provide additional details of the respective CDM programs under each rate class.

   i. If the programs do not appear on the Participant and Cost (P&C) Report, please indicate the source of the program savings.
   ii. Based on part i) above, please provide the supporting evidence (e.g. respective excel spreadsheets) for the 2019 and 2020 program savings allocated to the GS<50 kW and GS>50 kW classes.

c) If the proposed CDM manual adjustment of 6,769,360 kWh is comprised of actual savings, please discuss the need for a CDM manual adjustment as it should be capturing forecast savings only.

   i. Please discuss whether it is appropriate to include the remaining actual savings related to the CFF as part of the CDM variable in the load forecast.
   ii. Please clarify whether a LRAMVA threshold of 10,928,798 kWh is still required. If so, please explain.

Response:

a) BHI confirms that 28,270 kWh refers to actual savings from the Swimming Pool Efficiency Program. This value appears at Tab "LDC Progress" cell BQ43 of the April 2019 Participation and Cost report, filed as Attachment 14 in the Application.

b) BHI confirms that the GS<50 kW and GS>50 kW rate class savings in 2019 and 2020 are part of the Conservation First Framework (CFF). The types of CDM programs are identified in the measures category in the attachment filed as part of b) ii below.

   i. Program applications and savings are housed in Salesforce, a Customer Relationship Management ("CRM") software and Temagami, a customer application portal used to manage retrofit applications. This software and related processes are the same as used to inform the previous IESO P&C reports.

   ii. Please see IR_Attachment_3-Staff-39_BHI. This attachment includes data as filed in the Application and revised data.

c) The CDM adjustment pertains to 2019 CDM project savings that were not in place for the full 2019 year and forecast 2020 savings that were not yet in place.

   i. Despite the cancellation of the CFF, there are many projects there were not completed until 2020. The load forecast considers all CFF savings in 2019 and 2020 in a consistent manner as savings previously reported by the IESO. In the load forecast, half of 2019 savings, in addition to persistence of savings from previous years, is added to the class consumption dependent variable in the statistical regressions and then removed from predicted monthly consumption. The remaining half of 2019 savings is not fully reflected in the 2021 forecast. Savings in 2020 will further reduce class consumption so it is appropriate to include half of 2019 and full 2020 CDM savings as a CDM adjustment.

   ii. CDM savings data for 2019 in the load forecast is actual data and there is virtually no difference between a) including 2019 savings equal to 8,318,875 kWh as part of the LRAMVA threshold and applying 8,318,875 kWh actual savings for 2019 in subsequent LRAMVA claims and b) removing 8,318,875 kWh from the LRAMVA threshold and excluding 2019 from subsequent LRAMVA claims. BHI is indifferent to maintaining the LRAMVA threshold as proposed, or setting a lower LRAMVA threshold, equal to 2,609,923 kWh (2020 savings), and excluding persistence of 2019 projects in LRAMVA claims from the years 2020 onward.

Notwithstanding the above, the CDM adjustment is still required to consider half of 2019 project savings and full 2020 project savings that are not reflected in the forecast.

3-Staff-40

Other Revenue

Ref: Exhibit 3, pp. 70-77

Question(s):

a) Please provide a breakdown of specific service charges revenues as shown in Table 51 – Other Revenues, for each of the historical years (2014-2020) and the test year (2021).

b) Please provide a breakdown of miscellaneous income revenues as shown in Table 51 – Other Revenues, for each of the historical years (2014-2020) and the test year (2021).

c) Please confirm BHI expects to collect a revenue of $404,000 associated with the implementation of Metrolinx Regional Express Rail project in 2021.

Response:

a) Table 1 provides a breakdown of the specific service charges revenues for each of the historical years (2014 to 2019), the 2020 bridge year, and the 2021 test year.

Table 1

Specific Service Charge Revenue (4235)	2014	2015	2016	2017	2018	2019	2020	2021
Account Set Up Charges	$216,240	$211,456	$204,854	$207,236	$192,435	$187,644	$184,205	$185,580
Collection Charges	$530,991	$520,153	$592,320	$447,212	$462,783	$412,643	$491,040	$32,736
MicroFit Service Charges	$5,412	$7,395	$8,843	$9,901	$13,836	$14,399	$12,818	$12,067
Credit Checks / Returned Cheques Fees	$16,809	$12,810	$15,678	$17,261	$15,639	$14,517	$19,265	$19,390
Isolation Fees / Temporary OH Service Fees	$56,575	$87,800	$92,225	$98,451	$108,945	$94,600	$164,192	$162,087
Arrears Certificate Charges	$4,550	$4,353	$4,336	$4,483	$3,960	$3,324	$4,500	$4,500
Total	**$830,577**	**$843,967**	**$918,256**	**$784,544**	**$797,598**	**$727,127**	**$876,020**	**$416,360**

b) Table 2 provides a breakdown of the miscellaneous income revenues for each of the historical years (2014 to 2019), the 2020 bridge year, and the 2021 test year.

Table 2

Miscellaneous Income Revenue (4390)	2014	2015	2016	2017	2018	2019	2020	2021
Scrap Material Revenue	$20,884	$49,890	$87,642	$49,311	$38,795	$34,326	$9,154	$40,800
Project Material Handling Fee/Mobilization Fee							$474,000	$80,800
Recovery of Bad Debt (Prior Period)						$260,716		
Recovery of CDM Indirect Costs (Prior Period)						$574,048		
SRED Benefit	$125,876		$41,457	$44,550	$64,482	$97,754		
CGAAP Accounting Change	($140,199)							
CarryingChrge Retroact.Adj.Rev(EB-2014-0059)		$268,239						
Other Miscellaneous Income	$23,233	$26,962	$62,575	$20,913	$66,279	$37,145		
Total	**$29,794**	**$345,091**	**$191,674**	**$114,774**	**$169,556**	**$1,003,989**	**$483,154**	**$121,600**

c) BHI confirms it expects to collect a revenue of $404,000 in 2021 associated with the implementation of the Metrolinx Regional Express Rail project. Please refer to BHI's response to 3.0-VECC-42 g).

4-Staff-41

Ref: Appendix 2-JC

Question(s):

a) Please provide the updated year to date actual OM&A costs for 2020 in Appendix 2-JC format. Please specify how many months are actual vs. forecast.

Response:

a) BHI does not have an updated forecast for 2020 in Appendix 2-JC format. In addition, 2020 actual data is not available because BHI's year end processing is not complete.

4-Staff-42

Ref: Exhibit 4, pp. 14, 20

Question(s):

a) Table 5 (Exhibit 4, page 20 of 231) shows 90 FTEs in 2019 and 103 FTEs in 2020. Please explain why total salaries and benefits for 2019 is higher than 2020 as shown in Table 3 (Exhibit 4, page 14 of 231).

b) Please provide historical actual costs on computer software (2014-2018). Please identify OM&A programs in Appendix 2-JC that are contained in this computer software category.

Response:

a) The reason that Salaries and Benefits are lower in 2020 despite an increase in average headcount from 91 FTE to 96.5 FTE is due to:

- the deployment of two operations crews to the Metrolinx project (capital) for a portion of 2020 to complete the overhead distribution portion of certain phases as described on page 95 of Exhibit 4;
- a decrease in overtime of $214,268 in the control room program and the distribution maintenance and operations program; and
- a decrease in benefits due to the following:
    - fourteen employees left the organization in 2019 as identified in page 167 of Exhibit 4; and although the majority of these employees were hired in 2020, i) BHI has a wait period of six months for some benefits, during which it incurs no costs; and ii) BHI received a credit on its benefit premiums due to the COVID-19 pandemic shutdown and the subsequent inability of employees to visit healthcare practitioners.

b) BHI provides historical actual costs on computer software (2014-2018) by OM&A program in Appendix 2-JC in Table 1 below.

Table 1

Program	2014	2015	2016	2017	2018
Engineering	$266,515	$11,298	$150,897	$110,635	$126,650
Information Services	$227,203	$267,603	$242,426	$243,746	$162,465
Metering	$113,567	$121,528	$129,920	$139,915	$100,600
Station Maintenance and Operations	$26,955	$40,635	$29,737	$26,943	$28,141
Other	$676	($30)	$0	$100	$338
Total Computer Software	**$634,916**	**$441,034**	**$552,980**	**$521,339**	**$418,194**

4-Staff-43

Ref: Exhibit 4, page 15

Preamble:

When comparing 2021 OM&A with 2019 actuals, BHI stated that approximately 35% of the increase is due to inflationary increases, and the remaining 65% is a result of changes in BHI's operations.

Question(s):

a) Please provide calculations supporting numbers shown in Figure 2 (Exhibit 2, page 15 of 231) for each cost driver. Please explain assumptions used in the calculations (e.g. what inflation factor was used for 2020 and 2021).

b) Please compare 2019 actual OM&A with 2015 actuals by main cost drivers, please explain how much of the increase is driven by inflation and how much of the increase is a result of changes in BHI's operations. Please also provide supporting calculations.

Response:

a) BHI provides the calculations supporting the numbers shown in Figure 2 (Exhibit 2, page 15 of 231) for each cost driver in Table 1a) and 1b) below. Table 1b) identifies the assumptions for inflation.

Table 1a)

Description	2019 Actuals	Inflation 2019-2020	Inflation 2020-2021	Total Inflation	Non Inflationary Increase/ (Decrease)	Total Increase/ (Decrease	Total 2021 Test Year
Formula	**a (Application)**	**b = (1 + h)**	**c = (1 + i)**	**d = b + c**	**e = f - d**	**f = g - a**	**g (Application)**
Total Salaries and Benefits	$11,234,883	$232,769	$279,296	$512,066	$453,931	$965,997	$12,200,880
Temporary Staff	$415,977	$8,618	$10,341	$18,959	($273,834)	($254,875)	$161,102
Memo: Salaries and Benefits including Temp Staff (EP-5a)	**$11,650,860**	**$241,388**	**$289,637**	**$531,025**	**$180,097**	**$711,122**	**$12,361,982**
Consulting Fees	$669,749	$13,395	$13,663	$27,058	($197,495)	($170,437)	$499,312
Bad Debt Expense	$124,797	$2,496	$2,546	$5,042	$95,161	$100,203	$225,000
Postage/Mail Service/Stationery	$380,562	$7,611	$7,763	$15,375	$264,427	$279,802	$660,364
Rate Rebasing Costs	$0	$0	$0	$0	$169,769	$169,769	$169,769
OEB Regulatory Costs	$215,193	$4,304	$4,390	$8,694	$84,413	$93,107	$308,300
Computer Software	$629,190	$12,584	$12,835	$25,419	$179,660	$205,079	$834,269
Locates	$220,701	$4,414	$4,502	$8,916	$157,383	$166,299	$387,000
Vegetation Management	$527,241	$10,545	$10,756	$21,301	$219,960	$241,261	$768,502
Other	$4,670,251	$93,405	$95,273	$188,678	$424,349	$613,027	$5,283,279
Total	**$19,088,545**	**$390,141**	**$441,366**	**$831,508**	**$1,577,723**	**$2,409,231**	**$21,497,775**

Table 1b)

Description	Inflation 2019-2020 %	Inflation 2020-2021 %
Formula	**h**	**i**
Total Salaries and Benefits	2.1%	2.4%
Temporary Staff	2.1%	2.4%
Memo: Salaries and Benefits including Temp Staff (EP-5a)	2.1%	2.4%
Consulting Fees	2.0%	2.0%
Bad Debt Expense	2.0%	2.0%
Postage/Mail Service/Stationery	2.0%	2.0%
Rate Rebasing Costs	0.0%	0.0%
OEB Regulatory Costs	2.0%	2.0%
Computer Software	2.0%	2.0%
Locates	2.0%	2.0%
Vegetation Management	2.0%	2.0%
Other	2.0%	2.0%

b) BHI provides Table 2a) below to compare 2019 actual OM&A with 2015 actuals by main cost drivers. Table 2a) also identifies how much of the increase is driven by inflation; and how much of the increase is a result of changes in BHI's operations. Table 2b) identifies the assumptions for inflation. The calculations are identified in the formula rows of Table 2a) and Table 2b).

Table 2a)

Description	2015 Actuals	Inflation 2015-2016	Inflation 2016-2017	Inflation 2017-2018	Inflation 2018-2019	Total Inflation	Non Inflationary Increase/ (Decrease)	Total Increase/ (Decrease	2019 Actuals
Formula	a (Application)	b = a x (1 +j)	c = (a+b) x (1+k)	d = (a+b+c) x (1+l)	e=(a+b+c+d) x (1+m)	f = b to e	g = h - f	h = i - a	i (Application)
Salaries and Benefits (Base)	$8,858,250	$218,536	$196,664	$197,867	$195,530	$808,597	($81,738)	$726,858	$9,585,108
Overtime	$757,537	$18,689	$16,818	$16,921	$16,721	$69,149	$104,617	$173,766	$931,303
Incentive Pay	$405,042	$9,721	$9,540	$9,335	$9,540	$38,135	$275,295	$313,430	$718,472
Temporary Staff	$177,145	$2,126	$2,689	$3,639	$3,712	$12,166	$226,666	$238,832	$415,977
Consulting Fees	$294,681	$3,536	$4,473	$6,054	$6,175	$20,238	$354,830	$375,068	$669,749
Bad Debt Expense	$137,985	$1,656	$2,095	$2,835	$2,891	$9,477	($22,664)	($13,188)	$124,797
Postage/Mail Service/Stationery	$409,454	$4,913	$6,216	$8,412	$8,580	$28,121	($57,013)	($28,892)	$380,562
Rate Rebasing Costs	$98,788	$1,185	$1,500	$2,029	$2,070	$6,785	($105,572)	($98,788)	$0
OEB Regulatory Costs	$219,542	$2,635	$3,333	$4,510	$4,600	$15,078	($19,427)	($4,349)	$215,193
Computer Software	$441,034	$5,292	$6,695	$9,060	$9,242	$30,289	$157,867	$188,156	$629,190
Locates	$414,419	$4,973	$6,291	$8,514	$8,684	$28,461	($222,179)	($193,718)	$220,701
Vegetation Management	$647,315	$7,768	$9,826	$13,298	$13,564	$44,456	($164,530)	($120,074)	$527,241
Other	$4,855,374	$58,264	$73,705	$99,747	$101,742	$333,458	($518,580)	($185,122)	$4,670,251
Total	**$17,716,564**	**$339,294**	**$339,843**	**$382,221**	**$383,051**	**$1,444,410**	**($72,429)**	**$1,371,980**	**$19,088,545**

Table 2b)

Description	Inflation 2015-2016	Inflation 2016-2017	Inflation 2017-2018	Inflation 2018-2019
Formula	j	k	l	m
Salaries and Benefits (Base)	2.5%	2.2%	2.1%	2.1%
Overtime	2.5%	2.2%	2.1%	2.1%
Incentive Pay	2.4%	2.3%	2.2%	2.2%
Temporary Staff	1.2%	1.5%	2.0%	2.0%
Consulting Fees	1.2%	1.5%	2.0%	2.0%
Bad Debt Expense	1.2%	1.5%	2.0%	2.0%
Postage/Mail Service/Stationery	1.2%	1.5%	2.0%	2.0%
Rate Rebasing Costs	1.2%	1.5%	2.0%	2.0%
OEB Regulatory Costs	1.2%	1.5%	2.0%	2.0%
Computer Software	1.2%	1.5%	2.0%	2.0%
Locates	1.2%	1.5%	2.0%	2.0%
Vegetation Management	1.2%	1.5%	2.0%	2.0%
Other	1.2%	1.5%	2.0%	2.0%

4-Staff-44

Ref: Exhibit 4, page 19

Question(s):

a) Regarding the 24 FTEs identified under the Replacement/Workforce Planning column in Table 4 (Exhibit 4, page 19), please provide a breakdown by department to show how many of them are required to fill vacancies and how many of them are advance hires for retirements.

b) Has BHI filled all six new positions it planned for 2020? If not, please specify which position(s) were not filled at the end of 2020.

c) Does BHI have an established internal process to approve the business case for new positions? If so, please provide examples of the business case prepared for new positions filled in 2020.

Response:

a) BHI provides Table 1 below for 2019-2021 to identify the breakdown by department of the 24 FTEs to show how many of them are required to fill vacancies and how many of them are advanced hires for retirements.

BHI provides Table 2 below for 2019-2021 to reflect the actual vacancies at the end of 2020. There are 27 FTEs required to fill vacancies and advanced hires for retirements.

Table 1 (Recast Table 4, Exhibit 4, page 19 to breakdown Replacements and Workforce Planning)

Department	2019 Budget	2019 Actuals	Total Departures		Replace-ment	Workforce Planning	Re-deployed	New Position	2021 Forecast (Dec 31)	Net Change vs. 2019 Actuals
			Attrition (excl. Eliminated Position	Attrition Eliminated Position						
Accounting	5	5	-	-	1	-	(1)	-	5	-
Administration	5	4	(2)	-	2	-	-	-	4	-
Billing	4	4	-	-	1	-	(1)	-	4	-
Communications	2	1	-	-	-	-	-	1	2	1
Control Room	10	10	(2)	-	2	1	-	-	11	1
Customer Service	7	6	(1)	-	1	-	1	-	7	1
Distribution Maintenance and Operations	23	19	(2)	-	2	3	-	-	22	3
Engineering	17	15	(3)	-	4	-	1	2	19	4
Human Resources	2	2	-	-	1	1	-	-	4	2
Information Services	5	5	(1)	-	1	-	-	1	6	1
Metering	5	4	-	-	1	1	-	-	6	2
Purchasing	3	3	(1)	-	1	-	-	-	3	-
Regulatory	2	3	(1)	-	-	-	-	1	3	-
Regulatory - CDM	-	-	-	-	-	-	-	-	-	-
Safety	2	2	-	-	-	-	-	1	3	1
Stations Maintenance and Operations	8	7	-	-	-	1	-	-	8	1
Total	**100**	**90**	**(13)**	**-**	**17**	**7**	**-**	**6**	**107**	**17**

Table 2 (Recast Table 4, Exhibit 4, page 19 to breakdown Replacements and Workforce Planning and reflect 2020 actuals)

Department	2019 Budget	2019 Actuals	Total Departures: Attrition (excl. Eliminated Position	Total Departures: Attrition Eliminated Position	Replace-ment	Workforce Planning	Re-deployed	New Position	2021 Forecast (Dec 31)	Net Change vs. 2019 Actuals
Accounting	5	5	-	-	1	-	(1)	-	5	-
Administration	5	4	(2)	-	2	-	-	-	4	-
Billing	4	4	-	-	1	-	(1)	-	4	-
Communications	2	1	-	-	-	-	-	1	2	1
Control Room	10	10	(4)	-	4	1	-	-	11	1
Customer Service	7	6	(1)	-	1	-	1	-	7	1
Distribution Maintenance and Operations	23	19	(2)	-	2	3	-	-	22	3
Engineering	17	15	(3)	-	4	-	1	2	19	4
Human Resources	2	2	-	-	1	1	-	-	4	2
Information Services	5	5	(2)	-	2	-	-	1	6	1
Metering	5	4	-	-	1	1	-	-	6	2
Purchasing	3	3	(1)	-	1	-	-	-	3	-
Regulatory	2	3	(1)	-	-	-	-	1	3	-
Regulatory - CDM	-	-	-	-	-	-	-	-	-	-
Safety	2	2	(1)	-	1	-	-	1	3	1
Stations Maintenance and Operations	8	7	-	-	-	1	-	-	8	1
Total	**100**	**90**	**(17)**	**-**	**21**	**7**	**-**	**6**	**107**	**17**

b) BHI has filled four of the six new positions it planned for 2020. The two positions not filled are the System Architect - Technology Specialist, and the Facilities and Security Manager. Please refer to EP-16a).

c) BHI has an established internal process to approve new positions which is as follows:
   i. BHI business strategy is updated.
   ii. Business documents needs, requirements and prepares analysis.
   iii. Business submits request to HR.
   iv. BHI’s Workforce Plan is updated (as filed in Exhibit 4 Appendix A – BHI’s Five-Year Strategic Workforce Plan).
   v. BHI budgeting process and approval

BHI’s Workforce Plan serves as the business case for trades and technical positions, which includes engineering and IT.

4-Staff-45

Ref: Exhibit 4, page 22

Question(s):

a) Please explain how the 2021 bad debt expense of $200k was forecasted.

b) Is the increase of $100,203 in bad debt expense from 2019 actual to 2021 forecast a result of the COVID-19 pandemic?

Response:

a) BHI's methodology for forecasting annual bad debt expense is based on BHI's write-off procedures. Annual write offs are comprised of the prior period's 12 month finalized and uncollected accounts. For example, 2020 write offs will include all accounts that were finalized and uncollected for the period January 1 – December 31 2019.

   In establishing the forecast for 2021 bad debts, BHI reviewed actual uncollected and finalized accounts for the prior 12 month period. As the 2021 bad debt expense was forecast in July of 2020, only actual uncollected and finalized accounts for the period January 1 – June 30, 2020 were available. As this represented only 6 months of uncollected account activity, an estimate was made to encompass a full 12 month bad debt period. The known actual bad debts related to the period January 1 – June 30 2020 were $61,254. Doubling this amount to represent an estimate of the full 12 months from January 1 to December 31 provides an amount of $122.5k.

   Due to recent experience and future economic uncertainty an additional $77.5k was added to the forecast for a total of $200k.

b) See comments under part a).

4-Staff-46

Ref: Exhibit 4, pp. 34-37

Question(s):

a) Compared with 2019 actual, the proposed 2021 OM&A cost per customer will increase by 11%. Please explain how customers will benefit from this increase.

b) Using the 2019 Yearbook of Electricity Distributors, please compare BHI's OM&A cost per customer and OM&A cost per FTE with a peer group of local distribution companies (LDCs). Please explain the criteria for peer group selection and provide the list of selected LDCs. Please discuss the comparison results.

Response:

a) As stated above and identified in Table 1 below, BHI's 2021 OM&A per customer is expected to increase by 11% from 2019 to 2021, primarily driven by an increase in total OM&A of $2.4M as number of customers is expected to increase from 2019 to 2021 by 1.1%. The increase in total OM&A of $2.4M is comprised of inflationary increases of $831k and increases due to operational factors of $1,578k as identified in Table 2 of Exhibit 4. The two-year increase in OM&A excluding inflation is identified in Table 2 below – OM&A per customer is expected to increase by 3.5% on a compounded annual basis.

Table 1

Description (incl Inflation)	2019 Actual	2021 Test Year	Increase	% Increase	CAGR
Total OM&A	$19,088,544	$21,497,775	$2,409,231	12.6%	6.1%
# of customers	67,902	68,623	721	1.1%	0.5%
Total OM&A/customer	**$281**	**$313**	**$32**	**11.4%**	**5.6%**

Table 2

Description (excl Inflation)	2019 Actual	2021 Test Year	Increase	% Increase	CAGR
Total OM&A	$19,088,544	$20,666,268	$1,577,723	8.3%	4.1%
# of customers	67,902	68,623	721	1.1%	0.5%
Total OM&A/customer	**$281**	**$301**	**$20**	**7.1%**	**3.5%**

BHI identified the customer outcomes of the increase in OM&A from 2019 to 2021 throughout its Application; and a summary of the changes contributing to the increase of $2.4M is identified on pages 13-14 of Exhibit 4. BHI summarizes some of these outcomes from a customer perspective as follows:

- Facilitate customers' effective management of costs and signal conservation behaviour as a result of the transition to monthly billing (*$280k*);
- Mitigate increases in the number and frequency of outages through effective vegetation management (*$241k*);
- Reduce risk of infrastructure damage, loss of service, and injury as a result of responding to at least 90% of excavation (locate) requests within five business days (*$166k*);
- Ensure a sustainable and reliable energy sector which provides value; establishes reasonable rates and prices; and enacts and enables innovation. (OEB Cost Assessment) (*$93k*);
- Improve monitoring and control of equipment, utility mapping and asset management through enhancements to BHI's Control and Data Acquisition system ("SCADA") and an increase in support associated with BHI's Geographic Information System ("GIS") (Computer Software) (*$205k*);
- Opportunity for customers to voice their needs and preferences; and provide input into BHI's 2021 Distribution System Plan through comprehensive customer engagement (Rate Rebasing Costs) (*$170k*); and
- Increase/maintain customer support /services (*$1,154k* increase in salaries/benefits/other support of which $752k is attributable to inflation; *$100k* bad debt expense)
    - Deliver and maintain reliable electricity service - identified by customers as one of their top priorities in Phase 2 of BHI's customer engagement in this Application - by ensuring timely response to outages in the face of an increased incidence and severity of extreme weather events; equipment failures; and an increase in emergency and trouble calls[1];
    - Mitigate reactive repair costs by identifying worst performing segments of cable through sample cable testing and prioritizing them for proactive replacement[2];
    - Improve customer facing applications including BHI's Customer Outage Map (providing timely information on outages and restoration time to customers) and Customer e-Bill Portal[3];
    - Ensure mandated safety training for employees is conducted and renewed to protect employees and the public[4]; and
    - Improve BHI's management of customer/public communications through better utilization of the company's social media platforms, coordination of events (customer open houses, as well as internal town halls), and provision of customer service communications support.

[1] Exhibit 4, p 88
[2] Ibid., p 97
[3] Ibid., p 114
[4] Ibid., p 131

b) BHI has not provided the comparison requested since it reflects a benchmarking exercise that does not appropriately take into account the differences between the LDCs and, other than customer numbers, BHI has no insight as to individual characteristics to establish a proper peer group. Given the foregoing, BHI cannot provide a fulsome comment on the differences between OM&A per customer or OM&A per FTE on the basis of a peer group or industry average as it does not have access to the underlying data from the utilities that would be required to perform a thorough analysis. This underlying data (e.g., attributes of service area, distribution infrastructure, headcount by department) would account for differences in OM&A costs. A more accurate representation of whether BHI's OM&A is at an appropriate level is the benchmarking analysis conducted by the Pacific Economics Group ("PEG") for the OEB, in which distributor cost (OM&A and Capital) is estimated as a function of business conditions faced by each distributor.[5] As identified in Table 38 on page 117 of Exhibit 1, BHI's total costs for 2019 were (11.7%) lower than its predicted costs; and are forecast to be (5.7%) lower than its predicted costs in the 2021 Test Year.

[5] Report to the Ontario Energy Board: *Empirical Research in Support of Incentive Rate-Setting: 2019 Benchmarking Update,* page 2

4-Staff-47

Ref: Exhibit 4, page 38

Question(s):

a) Please provide a revised version of Table 14 to include overtime and incentive pay.

b) Please provide two versions of Table 14 (with and without overtime and incentive pay) to compare 2019 actual with 2021 test year budget.

Response:

a) BHI provides a revised version of Table 14 to include overtime and incentive pay in Table 1 below.

Table 1 (Recast Table 14, Exhibit 4 to include overtime and incentive pay)

Description	2014 Actuals (MIFRS)	2021 Test Year	2021 vs. 2014 Actuals Incr/(Decr)	2021 vs. 2014 CAGR
Salaries/Benefits/Overtime/Incentive Pay	$9,525,904	$12,200,880	$2,674,976	3.6%
FTE	100.0	102.6	2.6	0.4%
Salaries and Benefits per FTE	$95,259	$118,917	$23,658	3.2%

2014 Salaries/Benefits/Overtime/Incentive Pay per FTE	**$95,259**	
Annual Inflationary Increases	$16,151	68%
Step Progressions/Other	$7,507	32%
2021 Salaries and Benefits per FTE	**$118,917**	

b) BHI provides versions of Table 14 with and without overtime and incentive pay to compare 2019 actual with 2021 test year budget in Tables 2 and 3 below.

Table 2 (Recast Table 14, Exhibit 4 to compare 2019 Actuals to the 2021 Test Year) (excludes overtime and incentive pay)

Description	2019 Actuals	2021 Test Year	2021 vs. 2019 Actuals Incr/(Decr)	2021 vs. 2019 CAGR
Salaries and Benefits excl. Overtime/Incentive Pay	$9,585,108	$10,591,545	$1,006,437	5.1%
FTE	100.0	102.6	2.6	1.3%
Salaries and Benefits excl. Overtime/Incentive Pay per FTE	$95,851	$103,231	$7,380	3.8%

2019 Salaries and Benefits excl. Overtime/Incentive Pay per FTE	**$95,851**	
Annual Inflationary Increases	$4,369	59%
Step Progressions/Other	$3,012	41%
2021 Salaries and Benefits excl. Overtime/Incentive Pay per FTE	**$103,231**	

Table 3 (Recast Table 14, Exhibit 4 to compare 2019 Actuals to the 2021 Test Year)
(includes overtime and incentive pay)

Description	2019 Actuals	2021 Test Year	2021 vs. 2019 Actuals Incr/(Decr)	2021 vs. 2019 CAGR
Salaries/Benefits/Overtime/Incentive Pay	$11,234,883	$12,200,880	$965,997	4.2%
FTE	100.0	102.6	2.6	1.3%
Salaries/Benefits/Overtime/Incentive Pay per FTE	$112,349	$118,917	$6,568	2.9%

2019 Salaries/Benefits/Overtime/Incentive Pay per FTE	**$112,349**	
Annual Inflationary Increases	$5,121	78%
Step Progressions/Other	$1,447	22%
2019 Salaries/Benefits/Overtime/Incentive Pay per FTE	**$118,917**	

4-Staff-48

Ref: Exhibit 4, pp. 57-65

Question(s):

a) Please explain drivers for the increase of $295k in the Billing program from 2019 actual to 2021 budget.

b) Please expand Table 23 (Exhibit 4, page 61 of 231) to include the number of E-bill enrollments from February 1, 2020 to December 31, 2020. Please also add a row to Table 23 to show the percentage of customers enrolled in E-billing for each time period.

c) What's BHI's expected number of E-bill enrollments for 2021?

d) BHI stated that "New e-billing registrations (i) realized overall administrative savings of approximately $11 per year per customer, primarily driven by postage; and (ii) from January 1, 2017 onwards, partially offset the incremental costs of the transition to monthly billing." Please explain:

   i. How did BHI estimate the $11 per year per customer savings?
   ii. Has BHI reflected savings from e-billing registrations in its proposed 2021 OM&A budget?

Response:

a) The drivers for the increase of $295k in the Billing program from 2019 actual to 2021 budget are primarily due to the transition to monthly billing as described on page 58 of Exhibit 4; specifically the incremental costs of issuing twelve bills per year (monthly billing) as compared to six bills per year (bi-monthly billing) for customers on bi-monthly billing prior to 2017. Prior to the 2021 Test Year, these incremental costs were recorded in an OEB approved deferral and variance account and were not recorded in OM&A. In 2021, these costs will be recorded in OM&A. The remainder of the increase (approximately $40k) is due to an increase in salaries and benefits; and an increase in the costs associated with issuing paper bills (postage/mail service/stationery).

b) BHI has expanded Table 23 (Exhibit 4, page 61 of 231) to include the number of E-bill enrollments from February 1, 2020 to December 31, 2020; and the percentage of customers enrolled in E-billing for each time period. These figures are provided in Table 1 below.

Table 1

Description	Time Period				
Start Date	06/2011	09/15/2016	10/01/2017	06/01/2019	02/01/2020
End Date	09/14/2016	09/30/2017	05/31/2019	01/31/2020	12/31/2020
Campaign	n/a	Plant-a-Tree	n/a	Joseph Brant Museum	n/a
#E-bill Enrollments - Period	15,650	3,456	4,194	1,554	944
#E-bill Enrollments - Ending	15,650	19,106	23,300	24,854	25,798
% of Customers Enrolled	23%	28%	34%	36.50%	38%

c) BHI's expected number of enrollments during 2021 is 1,000.

d)

i. BHI quoted the $11 per year per customer savings based on avoided postage expense of $0.76/bill; and avoided printing and processing expense of $0.18/bill for twelve bills issued per year ($0.94 X 12 = $11.28/year). Upon review of this interrogatory, BHI realized that the $11 per year excluded stationery costs; and was based on 2017 data.

Per year customer savings in 2019 were $1.02/month or $12 per year, based on postage and printing/processing costs of $0.81/bill and $0.21/bill respectively.

ii. Yes, BHI reflected savings e-billing registrations in its proposed 2021 OM&A budget, with the exception of the e-billing registrations throughout 2021 of 1,000. This amount is estimated to be $6,529. Estimated savings are calculated in Table 2 below.

Table 2

Description	2021
Additional E-billing enrollments by end of year	1,000
Average E-billing Enrollments	500
Postage	$0.85
Mail Service	$0.20
Stationery	$0.08
Less E-bill Notification Cost	-$0.04
Total Net Savings per bill	**$1.09**
Net $ Savings (per bill)	$544
Net $ Savings (12 bills)	**$6,529**

4-Staff-49

Ref: Exhibit 4, pp.79-85

Question(s):

a) Please confirm the frequency of the vegetation management activity over the 2014-2019 period is a three-year cycle.

b) BHI stated that "The tendering process for the 2020-2022 cycle period was designed to award the contract to multiple vendors based on several criteria, not a sole vendor as had been past practice." What criteria were considered in the selection of multiple vendors?

c) What's the total contract price for the vegetation management activity for each of the cycles over 2014-2016 and 2017-2019?

d) What's the total contract price for the vegetation management activity for the 2020-2022 cycle?

e) Please provide a breakdown of vegetation management costs by components identified below for each of the historical years (2014-2020) and the test year (2021).

- Fixed price costs for scheduled vegetation management for a three-year cycle based on the contract pricing
- Variable costs from "as requested" line clearing work as a result of customer calls, trouble calls, and storm related work throughout the year
- Supervisory management

<u>Response:</u>

a) BHI confirms that the vegetation management activities over the 2014-2019 period are planned for three-year cycles.

b) The criteria that was considered in the selection of multiple vendors was as follows:

    a. Health and Safety due diligence (e.g. Commercial Vehicle Operator's Registration ("CVOR"), New Experimental Experience Rating ("NEER"), Critical Injury/Fatality rating, Incident Experience Rating)
    b. Crew availability and location
    c. References and experience
    d. RFP compliance

e. Pricing

c) Tables 1 and 2 below identify the total contract price for vegetation management for the cycles over 2014-2016 and 2017-2019 respectively. These amounts exclude the supervisory costs identified in Table 4 below.

Table 1

2014-2016 Vegetation Management Cycle	Contract Price
2014	$324,643
2015	$580,259
2016	$511,564
Total	**$1,416,466**

Table 2

2017-2019 Vegetation Management Cycle	Contract Price
2017	$428,496
2018	$346,530
2019	$385,250
Total	**$1,160,276**

d) The following table identifies the total contract price for the 2020 – 2022 cycle excluding "as requested" services and supervisory costs.

Table 3

2020-2022 Vegetation Management Cycle	Contract Price
2020	$432,293
2021	$654,791
2022	$352,794
Total	**$1,439,878**

e) BHI provides a breakdown of vegetation management costs by components identified below for each of the historical years (2014-2020) and the test year (2021).

Table 4

Year	Total	Planned	As requested	Supervisory
2014	$381,080	$271,250	$53,393	$56,437
2015	$647,315	$487,950	$92,309	$67,056
2016	$598,624	$389,530	$122,034	$87,060
2017	$574,272	$301,637	$126,859	$145,776
2018	$494,106	$217,764	$128,766	$147,576
2019	$527,241	$330,223	$55,027	$141,991
2020 Bridge Year [1]	$718,775	$432,293	$121,428	$165,054
2021 Test Year [1]	$768,502	$479,956	$123,492	$165,054
Total	**$4,709,914**	**$2,910,602**	**$823,308**	**$976,004**

1. See table below - planned amount of $432,293 is actual contract amount for 2020; Planned amount of $479,956 for 2021 is 3-year average contract amount (to avoid overstating 2021 OM&A); where 3-year contract is $432,293 - 2020, $654,791 - 2021, $352,784 - 2021

Table 5

Year	Contract Price	OM&A	Comments
2020 Bridge Year	$432,293	$432,293	reflected contract price in OM&A
2021 Test Year	$654,791	$479,956	reflected average of 3-year contract in OM&A to avoid overstating 2021 Test Year
2022	$352,784		
Average	**$479,956**		

4-Staff-50

Ref: Exhibit 4, page 92

Question(s):

a) Please expand Table 32 – Cost per Locate to include 2020 actual and 2021 forecast.

Response:

a) BHI expands Table 32 – Cost per Locate to include the 2020 and 2021 forecast in Table 1 below.

Table 1 (Expanded Table 32, Exhibit 4, page 92 to include 2020 and 2021)

Description	2014	2015	2016	2017	2018	2019	2020 Bridge Year	2021 Test Tear
# of locates	10,614	11,999	12,758	11,306	13,392	12,696	13,186	13,091
$ Cost of locates	$564,636	$414,419	$400,383	$347,127	$224,289	$220,701	$387,231	$387,000
$/locate	$53	$35	$31	$31	$17	$17	$29	$30

4-Staff-51

Ref: Exhibit 4, page 136

Preamble:

BHI proposed to adjust its OM&A expenditures in the 2021 test year by ($572,068) to smooth out its employee costs over the next five-year rate term.

Question(s):

a) Please provide supporting calculations explaining how this adjustment was derived.

b) Is there any capitalized portion of salaries and benefits associated with this 4.4 FTEs adjustment?

Response:

a) Please see Table 1 below for the supporting calculations explaining how the FTE adjustment was derived.

Table 1

Description	Formula	2021	2022	2023	2024	2025	5-Year average
FTE per Table 47, Exhibit 4	a	107.0	104.0	102.0	100.0	100.0	102.6
2021 FTE adjusted to average FTE over 2021-2025	b	102.6	102.6	102.6	102.6	102.6	102.6
Headcount Differential = # FTE adjustment	c = b - a	(4.4)	(1.4)	0.6	2.6	2.6	(0.0)
Salaries and Benefits/FTE	d	$130,015					
Salaries and Benefits for 4.4 FTE = # FTE Adjustment	**e = c x d**	**($572,068)**					

b) There is no capitalized portion of salaries and benefits associated with the 4.4 FTEs adjustment.

4-Staff-52

Ref: Exhibit 4, pp. 139-147

Preamble:

BHI discussed several challenges which informed and influenced its workforce planning and strategies.

Question(s):

a) BHI indicated that it has been presented with these challenges since its 2014 Cost of Service. Please explain how these long-lasting challenges are driving the need of an increase in FTEs from an average of 91.2 over the historical period (2014-2018) to an average of 102.6 over the forecast period (2021-2025).

b) BHI stated that "From 2014 to 2019, BHI experienced difficulty staffing vacancies in several departments due to the inability to find skilled labour." What has changed since 2019 that leads to the improvement in staffing vacancies? (from nine vacancies at the end of 2019 to planned zero vacancy at the end of 2020 and 2021).

c) How much lead time is required to hire in advance of retirements? Is it different for different positions/departments? If so, please specify the lead time required for each department.

Response:

a) BHI provided an explanation of how several long-lasting challenges are driving the need of an increase in FTEs from an average of 91.2 over the historical period (2014-2018) to an average of 102.6 over the forecast period (2021-2025) in Exhibit 4, Section 4.1.1.1, pages 15-20.

b) BHI created a new position in early 2019 - a Director of People and Culture. This position was filled on a temporary basis in 2019; and on a permanent basis in 2020. The position implemented HR programs that supported a more efficient recruitment process such as making improvements to job descriptions and researching best recruitment channels to attract the right candidates.

c) BHI has answered the question based on defining "lead time" as training overlap or the cross-over period i.e. the period of time from the start date of the new hire to the exit date of the retiree. It does not include the hiring process or the time for an apprentice to reach full proficiency which is identified in Table 9 of BHI's Five-Year Strategic Workforce Plan filed as Appendix A in Exhibit 4.

The lead time required to hire in advance of retirements is different for different positions and departments.

Trades positions: BHI requires a three to five years lead time to hire in advance of retirements for all trades positions irrespective of department.

Non-trades positions: The lead time varies depending on the positions and departments.

- Office Clerical positions in Billing, Accounting and Customer Service require about three to six months lead time;
- Office Engineering positions requires anywhere between six months and two years lead time depending on the position; and
- Office Managerial positions require anywhere between six months and two years lead time depending on the position and experience of incumbents.

4-Staff-53

Ref: Exhibit 4, pp. 153-154

Question(s):

a) Please provide a copy of the 2019 Management and Non-Union Employee Pay Report completed by Korn Ferry in December 2019.

b) Please explain if any changes were made to BHI's 2021 compensation plan after this 2019 review.

c) OEB staff notes that BHI filed its 2011 compensation benchmarking study for its non-union staff in the 2014 Cost of Service proceeding.[1] Please compare the 2011 study with the 2019 study and explain:

i. Changes in the comparator group selected in the reviews
ii. Changes in methodologies utilized for the design of the studies
iii. Changes in BHI's benchmarking results

d) Please provide a copy of the Incentive Program Review completed in October 2016 by Willis Towers Watson.

e) Please specify what changes were made to BHI's 2021 incentive pay plan after the 2016 Incentive Program Review.

f) Please expand Table 53 to include 2014 OEB-approved and actual amounts, 2020 actual if available, and 2021 forecast amount. Please explain what assumptions were used to forecast 2021 incentive pay.

<u>Response:</u>

a) BHI is not able to provide a copy of the 2019 Management and Non-Union Employee Pay Report completed by Korn Ferry. Most of BHI's management positions are filled by only one person and so provision of the report would amount to the disclosure of individual salaries, which constitutes personal information as that phrase is defined in the Freedom of Information and Protection of Privacy Act ("FIPPA"). This is consistent with the purpose of Section 2.4.3.1 ("Workforce Planning and Employee Compensation") of the OEB's Chapter 2 Filing Requirements, which states that "*where there are three or fewer employees in any category, the applicant must aggregate this category with the*

[1] EB-2013-0115, Interrogatory responses to Question 2.1 Staff 8, filed February 27, 2014.

category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees."

Furthermore, BHI has signed a non-disclosure agreement with Korn Ferry in relation to this report and is prohibited from sharing it externally.

b) BHI did not make significant changes to its 2021 compensation plan after the 2019 review, with the exception of setting salary grid job midpoint rates to the market data where appropriate.

c)

i. The only difference between BHI's 2011 compensation benchmarking study for its non-union staff as compared to the 2019 study is the database used for benchmarking. Both studies used Korn Ferry's "select utilities market" database; however, the 2011 study included utilities in Canada, whereas the 2019 study included utilities in Ontario only. In 2011 the number of Ontario utilities in the database was not large enough to provide an accurate benchmark. Any differences that occurred were due to the pool of data available in 2011 as compared to 2019.

ii. The same methodology was utilized for the design for both studies.

iii. The changes in BHI's benchmarking data were the following:

- In 2011, for each compensation element, the result showed that BHI was generally positioned near or above the 50th percentile of the "select utilities" and "all industrial" markets; and
- In 2019, the result showed that BHI was generally positioned at the 60th percentile of the "select utilities" and "all industrial" markets.

d) BHI is not able to provide a copy of the Incentive Program Review completed in October 2016 by Willis Towers Watson. BHI has signed a non-disclosure agreement with Willis Towers Watson in relation to this report and is prohibited from sharing it externally.

e) The changes made to BHI's 2021 incentive pay plan after the 2016 Incentive Plan Program Review were as follows:

i. Goals and objectives were changed to reflect industry and business strategic plan;
ii. Targets and thresholds for each goal were changed to reflect probability of achievement based on historical data. A stretch component was included for each target;

iii. The incentive percentage eligibility for some positions was changed according to market data to remain competitive;
iv. Ensured maximum payout award was competitive with market maximum. A 1.5x leverage to target was adopted.

The changes identified above were implemented commencing with the 2017 incentive plan.

f) BHI does not have the 2014 OEB approved data nor has it determined 2020 actual amounts.

BHI provides a recast Table 53 of Exhibit 4 as Table 1 below to include the 2014 actuals, the 2020 Bridge Year and the 2021 Test Year.

The forecast of 2020 incentive pay was based on historical average performance and expected achievement of targets and measures. For 2021, BHI applied an inflation factor of 2.0% to the 2020 forecast; and made an adjustment for those employees whose start date was in 2020 but were not eligible to receive a full year of incentive pay until 2021. The increase of 4% beyond inflation from 2020 to 2021 reflects this adjustment.

Table 1 (recast Table 53 of Exhibit 4 to include the 2014 actuals, the 2020 Bridge year and the 2021 Test Year)

	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Forecast	2021 Forecast	2014-2021 Average
Number of Employees	28	29	31	30	31	29	37	37	31.5
Average Amount	$13,854	$14,720	$15,515	$20,826	$20,977	$22,743	$19,521	$20,688	$18,606

4-Staff-54

Ref: Exhibit 4, pp. 158

Question(s):

a) As shown in Table 55, please explain how BHI managed its FTEs lower than the optimal budgeted level and managed the impact on its operations for each year over the 2014-2019 period.

b) Please provide a summary table to identify number of vacancies by department for each of the historical years (2014-2019).

Response:

a) Table 1 below identifies the strategies and actions that BHI has taken over the five years to continue to manage the operations of the business as effectively as possible with less-than-optimal budgeted FTEs; however as indicated in Table 1 there were negative operational and organization impacts.

Table 1

Strategies/Actions	Pro's	Operational Impact
Move individual's into 'Acting' roles	• Critical functions continue • 'Acting' employee learns new skills	• 'Acting' individual does not have 100% of skills & knowhow to do the full job • Accountabilities are often split between other individuals/manager, impacting their daily workload • 'Acting' employee's current job needs to be supported while in the Acting role. Causes additional workload for others taking on parts of his/her role • Heightened risk of errors, missed timelines, not meeting compliance and/or a safety incident (mind not on task) • More reactive than proactive approach a major impact/concern especially in high risk safety functions • Causes stress resulting in mental health concerns and can result in time off work
Absorb additional workload between existing staff complement		• Causes stress resulting in mental health concerns and can result in time off work • Above compounds the issue resulting in fewer active employees at work
Hire Contract employee during transition	• Dependent on level of experience, critical functions may continue	• If management role - the functions not able to be performed effectively are: o Managing employee performance o JH&SC participation o Recruitment activities o Sufficient training

The inability for BHI to achieve its budgeted FTE was driven by its high incidence of turnover from 2014 to 2019 (49%) as identified on page 29 of Exhibit 4. This had several implications as identified on pages 140-141 of Exhibit 4:

- A significant number of BHI employees have less than five years experience with the company[1];
- Priorities shifted to being proactive to one of being reactive which caused delays in filling of vacancies and budgeted positions;
- The workload of Hiring Managers increased which impacted their ability to fill the position quickly;
- Staff that were more experienced were required to work overtime as less experienced staff took longer to complete tasks or were not fully qualified to do the work - as a result experienced staff became stressed and experienced burnout as they were required to do the same/more with less experienced staff and resources;
- Some erosion of work and safety processes as knowledge of experienced workers was not transferred to new hires before departure - this could have resulted in compromised safety for employees and service for customers; and
- Retention of staff was affected - BHI turnover due to resignations more than doubled from the five-year period between 2010 to 2014 (five employees resigned) and the five-year period between 2015 to 2019 (fourteen employees resigned).

In short, BHI managed to fulfil its regulatory, safety, legal and customer obligations but at a cost. Operating below BHI's optimal staffing level is not sustainable. The year over year vacancies, with the exception of the control room supervisor, were not the same position - they were partial year vacancies across multiple departments which had a company-wide impact.

In addition, the changing business landscape and environment in which BHI operates in has changed significantly since 2014, making it increasingly difficult to manage risk and operate effectively and efficiently with less than the optimal FTE. BHI's mix of employees, and the nature of their skills, has changed to address significant technological and regulatory changes such as greater use of Information & Communications Technologies ("ICT"), smart grid applications, renewable technology integration, the electrification of transportation, and the decentralization of the electricity system through an increase in Distributed Energy Resources ("DERs")[2]. BHI has created and added several new positions to its staff complement to address the following[3]:

- Rapid technology advancements and associated emerging security issues;
- Skills shortage/gaps as a result of the above;
- An increase in distribution infrastructure and BHI property and buildings beyond the end of their useful lives; and
- Increasing requirements from regulatory and legislative bodies.

[1] Exhibit 4, Section 4.3.1.1, Figure 8
[2] Ibid., p 144
[3] Ibid., p 145

Operating without these critical resources could have a significant impact to BHI's operations; and the ability of BHI to manage below its optimal FTE from 2014-2019 does not translate into the ability to continue to do so in the future or for a prolonged period of time.

b) Please refer to CCC-23.

4-Staff-55

Ref: Appendix 2-K

Question(s):

a) Please provide a revised version of Appendix 2-K, Employee Costs, to reflect requests as follows:

A breakdown of management positions by executives and non-executive positions.
A breakdown of non-management employees by union and non-union.
A breakdown of total salary and wages by base salary and wages, overtime and incentive pay.
To show the expensed and capitalized compensation costs for historical (2014-2020) and the test year (2021).

Response:

a) BHI provides a revised version of OEB Appendix 2-K, Employee Costs in Table 1 below to provide:

- A breakdown of management positions by executives and non-executive positions.
- A breakdown of non-management employees by union and non-union.
- A breakdown of total salary and wages by base salary and wages, overtime and incentive pay.

A revised version of OEB Appendix 2-K is also attached as IR_Attachment_4-Staff-55_BHI to satisfy interrogatory 4-VECC-63.

The 2021 forecast annual increase percentage in Total Compensation of Management and Union has been added to the Table to satisfy interrogatory EP-13e).

BHI identifies the expensed and capitalized compensation costs for 2014 to 2019, the 2020 Bridge Year and the 2021 Test Year in Table 2 below.

Table 1

	2014 CoS (EB-2013-0115)	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Number of Employees (FTEs including Part-Time)[1]									
Executive	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Management	22.0	20.0	20.0	20.0	21.0	21.0	20.0	25.0	25.0
Non-Management (Non-Union)	5.0	5.0	5.0	6.0	6.0	6.0	5.0	8.0	9.0
Union	69.0	66.0	62.5	60.0	59.5	60.0	62.0	59.5	67.0
Total	100.0	95.0	91.5	90.0	90.5	91.0	91.0	96.5	105.0
BASE SALARIES & WAGES									
Executive	$812,648	$819,434	$871,415	$871,906	$893,947	$961,884	$944,436	$981,815	$1,126,355
Management	$2,062,001	$2,137,066	$2,207,599	$2,218,569	$2,245,686	$2,322,575	$2,445,422	$2,704,506	$2,944,786
Non-Management (Non-Union)	$454,197	$371,107	$386,914	$421,816	$565,726	$510,477	$464,692	$701,471	$924,620
Union	$5,293,363	$5,011,097	$5,175,117	$4,924,420	$4,956,285	$5,027,586	$5,045,677	$5,735,749	$6,139,303
Total	$8,622,209	$8,338,704	$8,641,045	$8,436,711	$8,661,644	$8,822,522	$8,900,227	$10,123,541	$11,135,064
OVERTIME									
Executive	$0	$0	$0	$0	$0	$0	$0	$0	$0
Management	$88,848	$76,495	$38,634	$23,493	$28,018	$27,194	$33,858	$8,493	$0
Non-Management (Non-Union)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Union	$979,034	$1,085,841	$1,110,082	$961,963	$968,372	$1,447,512	$1,047,989	$746,185	$810,980
Total	$1,067,882	$1,162,336	$1,148,716	$985,456	$996,390	$1,474,706	$1,081,847	$754,678	$810,980
INCENTIVE PAY									
Executive	$162,645	$165,302	$166,000	$174,872	$230,120	$275,320	$273,557	$297,520	$309,538
Management	$182,294	$192,225	$198,300	$227,300	$229,785	$313,620	$333,182	$291,385	$368,244
Non-Management (Non-Union)	$29,027	$23,325	$23,600	$24,700	$24,070	$40,860	$43,862	$30,650	$44,500
Union	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$373,966	$380,852	$387,900	$426,872	$483,975	$629,800	$650,601	$619,555	$722,282
Total Salary and Wages (including overtime and incentive pay)									
Executive	$975,293	$984,736	$1,037,415	$1,046,778	$1,124,067	$1,237,204	$1,217,993	$1,279,335	$1,435,893
Management	$2,333,143	$2,405,786	$2,444,533	$2,469,362	$2,503,489	$2,663,389	$2,812,462	$3,004,384	$3,313,030
Non-Management (Non-Union)	$483,224	$394,432	$410,514	$446,516	$589,796	$551,337	$508,554	$732,121	$969,120
Union	$6,272,397	$6,096,938	$6,285,199	$5,886,383	$5,924,657	$6,475,098	$6,093,666	$6,481,934	$6,950,283
Total	$10,064,057	$9,881,892	$10,177,661	$9,849,039	$10,142,009	$10,927,028	$10,632,675	$11,497,774	$12,668,326
Total Benefits (Current + Accrued)									
Executive	$286,213	$255,937	$268,726	$284,148	$289,438	$300,265	$299,325	$282,353	$276,415
Management	$619,411	$655,614	$680,714	$689,140	$685,653	$736,417	$759,852	$785,443	$916,966
Non-Management (Non-Union)	$141,192	$107,605	$112,083	$130,697	$174,034	$148,774	$117,511	$199,005	$260,698
Union	$1,688,899	$1,538,818	$1,545,286	$1,562,836	$1,571,524	$1,627,931	$1,496,625	$1,491,979	$1,706,092
Total	$2,735,715	$2,557,974	$2,606,809	$2,666,821	$2,720,649	$2,813,387	$2,673,313	$2,758,780	$3,160,171
Total Compensation (Salary, Wages, & Benefits)									
Executive	$1,261,506	$1,240,673	$1,306,141	$1,330,926	$1,413,505	$1,537,469	$1,517,318	$1,561,688	$1,712,308
Management	$2,952,554	$3,061,400	$3,125,247	$3,158,502	$3,189,142	$3,399,806	$3,572,314	$3,789,827	$4,229,996
Non-Management (Non-Union)	$624,416	$502,037	$522,597	$577,213	$763,830	$700,111	$626,065	$931,126	$1,229,818
Union	$7,961,296	$7,635,756	$7,830,485	$7,449,219	$7,496,181	$8,103,029	$7,590,291	$7,973,913	$8,656,375
Total	$12,799,772	$12,439,866	$12,784,470	$12,515,860	$12,862,658	$13,740,415	$13,305,988	$14,256,554	$15,828,497
Total Compensation Annual % Increase									
Executive		(1.7%)	5.3%	1.9%	6.2%	8.8%	(1.3%)	2.9%	9.6%
Management		3.7%	2.1%	1.1%	1.0%	6.6%	5.1%	6.1%	11.6%
Non-Management (Non-Union)		(19.6%)	4.1%	10.5%	32.3%	(8.3%)	(10.6%)	48.7%	32.1%
Union		(4.1%)	2.6%	(4.9%)	0.6%	8.1%	(6.3%)	5.1%	8.6%
Total		(2.8%)	2.8%	(2.1%)	2.8%	6.8%	(3.2%)	7.1%	11.0%

Table 2

Description	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Total Salary Per Appendix 2-K	**$12,439,866**	**$12,784,470**	**$12,515,860**	**$12,862,658**	**$13,740,415**	**$13,305,988**	**$14,256,554**	**$15,828,497**
Allocated to Capital	$2,086,661	$1,835,753	$1,835,095	$1,899,226	$1,865,987	$1,965,538	$1,753,435	$2,170,726
Allocated to OM&A	$10,353,205	$10,948,717	$10,680,765	$10,963,432	$11,874,428	$11,340,450	$12,503,119	$13,657,771

4-Staff-56

Ref: LRAMVA workform, Tab 5; Exhibit 4, pages 218/221

Preamble:

BHI's LRAMVA claim of $1,039,196 consists of lost revenue from 2019 activity and the persistence of 2013 to 2019 programs into 2020, inclusive of carrying charges to April 30, 2021.

BHI notes that it populated the LRAMVA workform with projects for which it has final savings, and will update in LRAMVA workform with projects from a Post-Project Submission in its interrogatory responses. BHI noted that most retrofit projects were not captured in the April 2019 P&C Report.

Question(s):

a) Please confirm why the additional projects included in this supplemental report were not identified on P&C Report, and explain why these programs are eligible for lost revenue recovery.

b) Please file an excel copy of the Post-Project Submission with the following information included:

- Framework under which the savings will be delivered under (e.g. CFF wind-down framework, interim framework, etc.)
- Date that the program was approved by the IESO
- Expected completion date of the program
- Expected kWh and kW savings (net)
- Delivery agent for the program savings (e.g. LDC or IESO led)
- Approval date of an IESO incentive

c) Please discuss at a program level how the persistence savings from 2019 into 2020 were derived, including the assumptions and reports used.

d) BHI mentioned that the contracted program participants in certain CFF programs are eligible for project extensions to June 30, 2021. Please discuss whether BHI foresees material lost revenues to be claimed in a future application beyond December 31, 2020, and from what types of projects?

<u>Response:</u>

a) The reason why the additional projects included in this supplemental report were not identified on P&C Report is because applications for these projects were submitted before April 1, 2019, but the documentation was not completed until after the last IESO

P&C report was issued in April 2019 (“P&C Report”). These savings are eligible for lost revenue recovery as they were eligible CFF programs for which participant agreements were in effect before April 1, 2019, as identified by the IESO in its Conservation First Framework Program Wind Down Guideline.[1]

b) The requested data is provided in updated tables on Tab 3a of the revised LRAMVA Workform filed as Attachment_2021 LRAMVA Workform_BHI_Revised. This data is based on the most recent data in BHI’s Salesforce database. All projects were delivered under the CFF framework and were BHI-led.

c) For all programs, with the exception of projects in the Retrofit and HPNC programs completed after the P&C Report, persistence into 2020 is identified in the P&C Report, and BHI used those values.

For Retrofit programs not included in the P&C Report, the persistence from 2019 to 2020 is calculated using the same rate of persistence for the Retrofit savings in the P&C Report. BHI notes that in the LRAMVA Workform in its Application, the persistence value in 2020 was not updated. This has been corrected in the updated LRAMVA Workform filed as Attachment_2021 LRAMVA Workform_BHI_Revised.

For the new HPNC project in 2019, added into the updated LRAMVA Workform filed in response to these interrogatories, the persistence into 2020 is estimated using the same rate of persistence of the HPNC program in 2018 to 2019.

d) Yes, there could be material lost revenues to be claimed in a future application beyond December 31, 2020. These lost revenues are from (i) savings persisting from January 1 to April 30, 2021; and (ii) savings from one HPNC project and 60 Retrofit projects, all of which have not been completed but for which a pre-project application was submitted.

[1] Conservation First Framework Program Wind Down Guideline Version 1.0, March 21, 2019, p1

4-Staff-57

Ref: LRAMVA workform, Tabs 3 and 5

Preamble:

BHI completed the transition to a fixed residential charge as of May 1, 2019, but it has claimed lost revenues from the residential class in 2019. As a result of the transition to the fixed residential charge, distributors will no longer experience lost revenues due to reduced consumption.

As the May 1, 2019 fixed residential charge is no longer a volumetric rate, the LRAMVA workform calculates residential lost revenues in 2019 by taking the full year value of persisting savings from prior years into 2019 and multiplying that amount by 1/3 of the 2018 volumetric rate (i.e. Jan 1 to April 30, 2019) to calculate lost revenues for 2019, as this period was before the fixed residential charge was in place.

Question(s):

a) Please provide rationale for claiming lost revenues for the residential class for all of 2019 when the utility has transitioned to a fixed residential charge as of May 1, 2019.

Response:

a) BHI did not claim lost revenues for the residential class for all of 2019. Tab 5 of the LRAMVA Workform includes full year savings in order to be consistent with the IESO reports. Those full year savings are multiplied by 1/3 of the volumetric rate (i.e., January 1 to April 30, 2019) to account for the transition to a fixed residential charge as of May 1, 2019. Another way to calculate the lost revenues for only the portion of 2019 for which residential customers were not on fully fixed rates is to divide the full year savings for 2019 by three and multiply by the variable rate in effect from January 1 to April 30, 2019, which was $0.0042/kWh; however this has the same effect as the calculation in the LRAMVA Workform.

4-Staff-58

Ref: Exhibit 4, page 224; LRAMVA workforms, Tab 8 – 2020 IRM (EB-2019-0023) and 2021 COS

Preamble:

The Application indicates there were no changes to the street lighting savings claimed since the 2020 IRM application, and only the persistence of savings is captured in 2019 and 2020. However, the persistence of street lighting savings included in the LRAMVA workform in this proceeding are higher than the savings claimed from both street lighting projects (#1 and 2) in the previous LRAMVA application.

Question(s):

a) Please confirm that the methodology used to calculate street lighting savings captures only incremental street lights from the municipality's participation in the IESO program.

b) In Tab 8 of the LRAMVA workform filed in this proceeding, please explain what the billed demand data in 2017 and 2018 (column C) represents, and reconcile the billed demand kW values (column C) to the pre- and post-demand data (columns L and Q) in the project level tables. Please discuss by project.

c) The number of bulbs replaced did not change materially (i.e. from 7,313 to 7,316 bulbs for project #1, and from 7,600 to 7,698 bulbs for project #2) between the current and previous LRAMVA workform filed in the 2020 IRM proceeding.

   i. Please explain why cumulative gross billed demand has increased by 63% for project #1 (from 366 kW to 594 kW) and project #2 (from 455 kW to 742 kW) and why this change is appropriate.

Response:

a) BHI confirms that the methodology used to calculate streetlight savings only captures incremental streetlights from the municipality's participation in the IESO program.

b) The billed demand in column C is the demand that was billed to customers in each month indicated. It includes lights that were not retrofitted. Column L and Q represent the wattage and number of lights that were retrofitted. Column L is the wattage and quantity of the lights that were changed out. Column Q represents the wattage and quantity of the new lights installed. Table 1 below reconciles the gross kW reductions (column D) to the pre and post demand data (columns L and Q) in the project level tables. Column C is the previous months billed demand minus the Gross kW reduction in column D (e.g., the Dec-17 value in C38 is equal to the Nov-17 value in C37 less the gross kW reduction in cell D38 (i.e., 2029.26 kW = 2285.95 kW – 256.69 kW).

Table 1

Project	kW Before	kW After	kW Savings	Reference 1	Reference 2
	Column L	Column Q	Q-L	Column E	Column D
Project 1	996.28	402.15	594.13	Cell E38	Cells D36:D38
Project 2	1,252.15	510.09	742.07	Cell E60	Cells D49:D60

c) BHI agrees that the number of bulbs replaced did not change materially (i.e., from 7,313 to 7,316 bulbs for project #1, and from 7,600 to 7,698 bulbs for project #2) between the current and previous LRAMVA Workform filed in its 2020 IRM proceeding.[1]

i. The cumulative gross ***billed demand*** did not increase as identified in Board Staff's interrogatory above. The cumulative gross ***kW reduction*** did increase by 63% for project #1 (from 366 kW to 594 kW) and project #2 (from 455 kW to 742 kW). The main reason for the difference is that the 2020 IRM application used nominal wattage instead of true wattage to determine demand savings. This was not known until after a decision had been reached on BHI's 2020 IRM application; however the claim for LRAMVA from streetlighting was lower than it should have been in the 2020 IRM application as demand savings were understated.

[1] EB-2019-0023

4-Staff-59

Ref: LRAMVA workform, Tab 1-a

Preamble:

If BHI made any changes to the LRAMVA workform as a result of its responses to the above LRAMVA interrogatories, please file an updated LRAMVA workform, and confirm the LRAMVA balance requested for disposition, the disposition period and the revised rate riders.

Question(s):

a) Please confirm that any changes to the LRAMVA workform in response to any LRAMVA interrogatories are reflected in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

b) Please ensure that any analysis or supporting documentation filed in response to the above LRAMVA questions do not contain personal information. Please ensure that all confidential information is removed or treated in accordance with Rule 9A of the OEB's *Rules of Practice and Procedure*.

Response:

a) BHI confirms that any changes to the worksheet have been identified in Table A-2 of the LRAMVA Workform filed as Attachment_2021 LRAMVA Workform_BHI_Revised.

b) BHI confirms that no personal information has been included in the LRAMVA Workform or in its interrogatory responses.

4-Staff-60

Errors in Useful Lives in Last Rebasing Application

Ref 1: Exhibit 4, pages 203-204

Preamble:

BHI states that it has identified some errors in its last rebasing application regarding the useful lives of certain assets: useful lives for some assets were reported incorrectly in 2014 Appendix 2-BB which is shown in the table below:

Table 84 - Useful Lives Incorrectly Reported in 2014 Cost of Service

Category Component	Correct Useful Life	Useful Life (Reported in 2014)	Reason
Fully Dressed Concrete Poles	60	40	reported useful life for wood poles instead of concrete poles
Communication Equipment - Towers	60	10	reported useful life for communications - wireless instead of communications - towers
Repeaters - Smart Metering	15	5	reported useful life for office furniture & equipment instead of repeaters
Data Collectors -Smart Metering	15	5	reported useful life for office furniture & equipment instead of data collectors

BHI also states that “there were some asset categories for which a useful life was not reported in the 2014 Cost of Service although BHI owns these asset categories; or the asset category was assigned to the wrong USoA Account”. These assets are identified in the table below:

Table 85 - Asset Categories Missing from 2014 Cost of Service

Category Component	Correct Useful Life	Useful Life (Reported in 2014)	Reason
Station Service Transformer	60	-	BHI did not include in 2014 Appendix 2-BB in error
Solid State Relays	30	30	BHI listed as Distribution Station Equipment instead of System Supervisory Equipment
Remote SCADA	20	-	BHI did not include in 2014 Appendix 2-BB in error
SCADA – Transducer	10	-	not listed in the 2014 Appendix 2-BB
Automobiiles	8	-	not listed in the 2014 Appendix 2-BB
Wholesale Energy Meters	20	-	not listed in the 2014 Appendix 2-BB

Question(s):

a) Was there any rate impact of the errors identified in 2014 rebasing application? If so, please explain and quantify the rate impact.

<u>Response:</u>

a) No, there was no rate impact of the errors identified in BHI’s 2014 rebasing application. The correct useful lives were used to calculate depreciation and amortization.

4-Staff-61

Loss Carry forward
Ref 1: Exhibit 4, page 208
Ref 2: Attachment 27_2021 PILs Workform

Preamble:

BHI states that:

BHI did not have any non-capital loss carry-forwards at the end of 2019; however it expects to incur a non-capital loss of ($284,753) as identified on Tab "B4 Sch 4 Loss Cfwd Bridge" of the PILS model. BHI expects to use 100% of the non-capital loss carry-forward in 2021. BHI had a capital loss carry-forward at December 31, 2019 of $85,869. BHI does not expect to use this capital loss in 2021.

OEB notes from the PILs workform that BHI realized a non-capital loss of $1,524,915 in 2019 but this loss is not entered into Tab H4 Schedule 3 Loss Cfwd Hist of the PILs workform.

Question(s):

a) Please explain why the loss incurred in 2019 of $1,524,915 is not entered into the Tab H4 of the PILs workform.

b) Please confirm if the non-capital loss of $284,753 in the bridge year 2020 has been updated since the filing date of the pre-filed evidence. If so, please provide an updated figure.

c) Please explain the nature of the capital loss of $85,869 and why BHI does not expect to use this capital loss in 2021.

Response:

a) The non-capital loss of $1,524,915 incurred in the 2019 taxation year was carried back to the 2016 taxation year on the 2019 PILs return. As a result, there is no non-capital loss closing balance to be carried forward to future years. Please refer to Appendix B: 4-Staff-61 a).

   Since there is no Non-Capital Loss Carry-forward balance at the end of 2019, no amount was entered in Tab H4 of the PILs Workform filed as Attachment_2021_PILS_Workform_BHI_Revised.

b) As a result of certain changes made to the revenue requirement in response to these interrogatories, the non-capital loss for the Bridge year has been updated to be

($470,137). A copy of the updated calculation is included in the updated PILs Model, Tab B1 filed as Attachment_2021_PILS_Workform_BHI_Revised.

c) The capital loss of $85,869 arose as a result of a disposition of capital property in historical periods. BHI does not expect to have any taxable capital gains in the Bridge Year or Test Year, against which it can use the capital loss of $85,869. As a result, the capital loss of $85,869 is carried forward to future taxation years.

4-Staff-62

PILs Expense
Ref 1: Attachment 27_2021 PILs Workform
Ref 2: the OEB's Letter "Accounting Direction Regarding Bill C-97", July 25, 2019

Preamble:

BHI has applied accelerated capital cost allowance (CCA) in the PILs model, in accordance with the new Accelerated Investment Incentive Program (AIIP). In the OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, it states that:

> The OEB recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB may consider a smoothing mechanism to address this.

Question(s):

a) Please confirm that all of BHI's capital additions in the 2021 test year are forecasted to be eligible for the AIIP.

b) Please discuss whether BHI has considered smoothing of accelerated CCA for all its capital additions and what its conclusion is.

c) Please provide a calculation showing how BHI would smooth CCA over the IRM period, and what the impact to PILs would be under a smoothed and unsmoothed scenario.

d) Assuming the current proposed capital additions are approved in this rate application, please provide the balance in Account 1592 sub-account CCA changes as at end of the IRM term, i.e. 2025, for the full revenue impacts of the phasing out of the AIIP.

Response:

a) BHI confirms that all capital additions in the 2021 Test Year are forecasted to be eligible for AIIP.

b) BHI completed the PILs Model in the Application without editing the OEB formulas, thereby taking full AIIP using the 1.5x factor in the 2021 Test Year. BHI confirmed it "maximized CCA" in the integrity checks in the PILs Model in the Application. BHI initially intended to utilize Account 1592 for the duration of the rate-setting term to account for any differences that arise as a result of the phase-out of the AIIP rules in 2024 and 2025. For these reasons, BHI did not propose a smoothing mechanism in this

Application. However, BHI would consider smoothing the differences by accruing for the 2024 and 2025 differences resulting from the AIIP change in Account 1592 and disposing of the balance in this Application.

c) The AIIP phase-out will begin for depreciable property available for use after 2023. For 2024 and 2025, BHI assumed that all capital additions will qualify as eligible property for AIIP. Please refer to Appendix C: 4-Staff-62 c) for a sample calculation of the 2021 Test Year CCA on additions, using the 1.5x factor and the 1.0x factor, and a comparison between the two calculations. The CCA in 2021 to 2023 is based on the current 1.5x AIIP factor, and the 2024 and 2025 calculation is based on the 1.0x AIIP factor, as proposed in the 2024-2027 phase-out period. The additions are based on the revised capital additions updated in response to these interrogatories.

The "smoothed" scenario results in annual CCA of $9,163,254 from 2021-2025. The 2021 Test Year CCA, updated for revenue requirement changes in response to these interrogatories is $9,366,575. The difference between the 2021 Test Year CCA, as filed in the updated PILs Workform, and CCA using the "smoothed" scenario, is $203,321 ($53,880 per year tax effected, or $269,400 for the 5-year rate-setting period). This smoothing calculation is provided in Appendix D: 4-Staff-62 c).

As stated above, BHI originally intended to recover the actual difference in AIIP from ratepayers through Account 1592 in future years; however, BHI would consider including $366,530 ($269,400 grossed up) in Account 1592 and disposing of this balance in this Application, along with the remainder of that account, which relates to AIIP differences calculated from 2018-2020.

d) Assuming the current proposed capital additions are approved in this rate application, BHI provides the balance of ($366,530) in Account 1592 sub-account for the CCA changes in Table 1 below, as at the end of the IRM term, i.e. 2025. This balance represents the full revenue impacts of the AIIP phase-out in 2024 and 2025. The amounts for 2024 and 2025 are identified in Appendix D: 4-Staff-62 c).

Table 1

Description	2021	2022	2023	2024	2025	Principal Balance at end of IR Term
CCA Difference	$0	$0	$0	($538,170)	($478,433)	($1,016,603)
Tax Impact	$0	$0	$0	($142,615)	($126,785)	($269,400)
Grossed Up PILS	$0	$0	$0	($194,034)	($172,496)	($366,530)

5-Staff-63

Ref: Exhibit 5/pages 4, 7 and 8

Preamble:

BHI documents that it has a Promissory Note due to the City of Burlington. The note has a principal of $47,878,608 and attracts a rate equal to the OEB's deemed long-term debt rate. BHI used the 2020 deemed long-term debt rate for this debt in its original application but stated that the rate would be updated.

BHI also forecasts new long-term debt of $10 million for a term of 25 years from Infrastructure Ontario. In its Application, Burlington Hydro has assumed a rate of 3.21% for the new loan; this rate is equal to the 2020 deemed long-term debt rate.

On page 4, BHI stated that it will update its cost of capital parameters based on the OEB-issued 2021 cost of capital parameters once those become available.

The OEB issued the updated cost of capital parameters for 2021 on November 9, 2020, by way of letter.[1] The deemed long-term debt rate for 2021 is 2.85%.

Question(s):

a) Please provide updated information on the status of the new forecasted loan with Infrastructure Ontario, including the principal, date that the loan is being executed on, term, and rate.

b) Please confirm that the Promissory Note due to the City of Burlington will attract the 2021 deemed long-term debt rate of 2.85% as of January 1, 2021.

c) Please update Appendices 2-OA, 2-OB, and the RRWF to reflect changes in BHI's cost of capital parameters in light of the OEB's letter on 2021 cost of capital parameters and the responses to a) and b) above.

Response:

a) On December 22, 2020, negotiations were finalized with the TD Bank, rather than Infrastructure Ontario, for a $15 million term loan available in tranches of $5 million per draw to a maximum of $10 million per annum. Maximum amortization period available is 360 months with a fixed rate option between 12 and 120 months. Fixed rates will be

[1] OEB letter on 2021 Cost of Capital Parameters, November 9, 2020

determined at drawdown, subject to term chosen. Security and legal documentation are currently in progress with exact timing of completion not known.

The principal amount in the 2021 Test Year has been revised to $5MM from the amount filed in the Application of $10MM.

b) BHI cannot confirm that the Promissory Note due to the City of Burlington will attract the 2021 deemed long-term debt rate of 2.85% as of January 1, 2021.

The Promissory Note due to the City of Burlington will attract the 2021 deemed long-term debt rate of 2.85% as of May 1, 2021, the proposed effective date of BHI's 2021 rebasing rates. The existing long term date rate of 4.88% on the Promissory Note is in effect until April 30, 2021.

c) BHI provides updates to Appendices 2-OA, 2-OB, and the RRWF to reflect:

i. changes in BHI's cost of capital parameters in light of the OEB's letter on 2021 cost of capital parameters
ii. its response to part a).

There is no change to Appendices 2-OA, 2-OB, and the RRWF as a result of BHI's response to part b) above.

These changes are reflected in the following attachments:

- Attachment_Main_OEB_Chapter2Appendices_BHI_Revised
- Attachment_2020RRWF_BHI_Revised

7-Staff-64

Meter Counts
Ref: Cost Allocation Model Tab I7.1 Meter Capital; I6.2 Customer Data

Preamble:

In the GS < 50 rate class, BHI has entered a total of 5,344 meters of various types. There are forecasted to be 5,564 customers forecasted to be in the rate class.

Question(s):

a) Please reconcile the apparent discrepancy.

<u>Response:</u>

a) Please refer to BHI's response to 7.0-VECC-72 a) for a reconciliation of the GS<50 kW discrepancy between meters and customers.

7-Staff-65

Weighting Factors
Ref: Exhibit 7, page 10

Preamble:

In determining the service weighting factors, BHI states that it calculated the cost of installing a typical service for each customer class.

BHI states that it determined the billing and collecting costs directly attributable to each rate class and allocated the remaining not-directly attributable costs.

Question(s):

a) Please provide the installed cost (paid by BHI) of a typical service for each customer class.

b) Please provide the proportion of customers in each class where BHI is responsible for providing and maintaining a service connection.

c) Please provide the derivation of the resulting weighting factors. In doing so, please indicate whether each cost was directly attributable or allocated.

d) For each allocated cost, please indicate the allocation methodology use.

Response:

In preparing the response to this interrogatory, BHI identified that the service weighting factors used in the cost allocation model were based on gross cost instead of installed cost (paid by BHI). BHI has corrected the Cost Allocation Model filed in response to these interrogatories to use installed cost to determine its service weighting factors. Please refer to BHI’s response to 1-Staff-1 for more information on the model update.

a) BHI provides the installed cost (paid by BHI) of a typical service for each customer class in Table 1 below.

Table 1

Rate Class	Length	Type 1 Description	Type 2 Description	Type 3 Description	Type 4 Description
Residential	40m	O/H = $628	U/G = $628	Subdivisions = $429	Condo Hi-rise = $0
GS<50 kW	40m	OH = $655	U/G (from Secondary Connection Pedestal ("SCP")) = $0	U/G (from Padmount Tx) = $0	
GS>50 kW		U/G (from Padmount Tx) = $0			
Streetlights		O/H or U/G = $31 (average 10 lights per Connection, assuming connection at Demarcation point)			
USL		O/H or U/G = $313 (assuming connection at Demarcation point)			

b) BHI provides the proportion of customers in each class where BHI is responsible for providing and maintaining a service connection in Table 2 below.

Table 2

Type	Proportion of Customers / Comment
Residential (40m length) O/H & U/G	BHI maintains 100% of primary and secondary side
GS<50 kW (40m length) O/H	BHI maintains 100% of primary and secondary side
GS<50 kW U/G	BHI maintains 100% of primary and up to Demarcation Point (Secondary Connection Pedestal ("SCP")) secondary side. Customer responsible beyond Demarcation point ("SCP")
GS>50 kW U/G (from Padmount Tx)	BHI maintains 100% of primary up to Demarcation Point (secondary spades on padmount transformer). Customer responsible beyond Demarcation point.
Streetlights O/H or U/G	BHI maintains 100% of primary up to Demarcation Point. Customer responsible beyond Demarcation point.
USL O/H or U/G	BHI maintains 100% of primary up to Demarcation Point. Customer responsible beyond Demarcation point.

c) BHI provides the derivation of the resulting weighting factors in Table 3 below. BHI has also identified whether each cost was directly attributable or allocated; and the allocation methodology used.

Table 3

Cost	USoA	Directly Atrributable/ Allocated	Methodology	Total	Residential	GS<50 kW	GS>50 kW	USL	SL
Customer Billing - Bill Production/ Presentment/Print	5315	Directly Attributable	Cost/Bill x # bills	$682,858	$611,534	$57,214	$13,864	$226	$21
Customer Billing - All Other	5315	Allocated	Total = remainder of Customer Billing Cost. Allocated on Direct Customer Billing Costs.	$449,559	$402,603	$37,667	$9,127	$149	$14
Collecting	5320	Allocated	Total = actual Collecting Cost; allocated to rate class based on proportion of total bad debt expense for past 3 years.	$276,682	$105,039	$50,011	$121,631	$0	$0
Collection Charges	5330	Allocated	Total = actual Collection Charges costs. Allocated to rate class based on proportion of total bad debt expense for past 3 years.	$132,786	$50,411	$24,002	$58,374	$0	$0
Miscellaneous Customer Accounts Expense	5340	Allocated	Total = actual Miscellaneous Customer Accounts Cost . Allocated to rate class based on proportion of total other expenses above (5315,5320,5330)	$697,441	$529,040	$76,396	$91,821	$169	$16
# of bills				817,803	739,532	66,088	11,857	289	36
Total Billing Cost per Bill				$2.74	$2.30	$3.71	$24.86	$1.88	$1.39
Weighting Factor					**1.00**	**1.62**	**10.82**	**0.82**	**0.61**

d) Please refer to part c) above.

7-Staff-66

Load Profiles

Ref: Ex 7, Page 5

Preamble:

BHI used 2018 load profiles as the basis for its load profile updates.

Question(s):

a) Please explain why 2019 data was not used.

b) If the required data is available, please provide updated load profiles using the same methodology and 2019 profiles as the basis.

c) If the resulting load profiles are materially different, please explain why BHI believes this to be the case.

<u>Response:</u>

a) BHI obtained 2016 to 2018 load data in 2019 in preparation for its planned August 2020 filing, prior to 2019 full year data being available. The process to obtain and process the data was time consuming and costly and as such BHI elected not to obtain 2019 data to update the model again.

b) The required data is not available. Refer to part a) above. BHI is not able to obtain the 2019 load data within the required time frame.

c) BHI does not believe load profiles derived using 2019 data would be materially different from load profiles derived using 2016-2018 data. This assessment factored into the decision to not update the load profiles.

7-Staff-67

Load Profiles
Ref: Ex 7, Page 12

Preamble:

BHI states that “all residential and GS<50 kW customers have a smart meter.” With respect to GS < 50kW, approximately 50% have an interval meter.

Question(s):

a) As of January 1, 2018, please indicate the proportion of customers in each rate class that had a meter capable of measuring energy use over intervals no longer than one hour.

b) As of January 1, 2019, please indicate the proportion of customers in each rate class that had a meter capable of measuring energy use over intervals no longer than one hour.

c) If the answer in part a) is not 100% for all rate classes, please explain how the historic load profiles were produced for those rate classes where not all customers had a metering arrangement capable of measuring hourly energy use.

d) Please provide the data sources for each metering arrangement, the data validation approaches used, and how any missing data is addressed.

e) Please explain whether the hourly load profiles include losses.

f) Does BHI have any primary metered customers?

g) If any adjustments were made for losses, please explain the adjustments made.

Response:

BHI would like to clarify the evidence on page 12 of Exhibit 7 where it stated that approximately 50% of GS>50 kW customers have an interval meter. This statement is correct. The remaining 50% have a smart meter, meaning all customers in the GS>50 kW rate class have a meter capable of measuring energy use over intervals no longer than one hour.

a) As of January 1, 2018, 100% of customers in the residential, GS>50 kW and GS>50 kW rate classes had a meter capable of measuring energy use over intervals no longer than one hour.

b) As of January 1, 2019, 100% of customers in the residential, GS>50 kW and GS>50 kW rate classes had a meter capable of measuring energy use over intervals no longer than one hour.

c) n/a. Please refer to part a) above.

d) Olameter provided the data for the Residential and GS<50 kW rate classes; and Utilismart provided the data for the GS>50 kW rate classes.

   Data validations were completed by the MV90 system. There are flags in the MV90 system that can be enabled (or disabled) for different data issues within a meter read. If the validation of a meter read fails one of these enabled checks, the MV90 system will flag the data, and put the data file on hold (an "edit") until the MV90 operator reviews the edit and accepts it or corrects it. Once the validation is accepted, the data flow continues into the export. Anything in the MV90 data directory that is "Accepted" has passed the validation checks.

   Missing data was addressed by using scaling factors. Hourly loads of customers with data available was scaled to 2021 forecast class consumption, accounting for both the change in consumption from 2018 to 2021 and for any missing data.

e) The hourly load profiles do not include losses.

f) Yes, BHI has primary metered customers.

g) No adjustments were made for losses.

7-Staff-68

Load Profiles
Ref: Load Profile Derivation model, sheet 2021 Load Profiles

Preamble:

OEB staff has determined that the sum of the hourly load profiles Unmetered Scattered Load (USL) profile, in column I of the above reference indicates that between 255 and 282 kWh is used in each of the 8760 hours of the year. These values total 2,282,357 kWh. BHI has forecasted 3,103,371 kWh of energy consumption for the USL rate class.

For each of the other rate classes, the sum of the 8760 hours totals the class energy forecast for 2021.

Question(s):

a) Please confirm OEB staff's understanding as set out above or provide a correction and explain the difference.

b) Please confirm that these hourly profiles underpin the demand allocators without any further scaling or adjustment.

c) Please explain the variance in the USL rate class between the total consumption of the profile hours, and the 2021 energy forecast.

Response:

a) BHI confirms OEB Staff's understanding as set out in the preamble.

b) BHI confirms that confirm that these hourly profiles underpin the demand allocators without any further scaling or adjustment.

c) The variance is caused by a reference error in the USL column (column I) of the 2021 Load Profiles tab. This has been corrected in the I8 Demand Data tab of the revised Cost Allocation Model filed as Attachment_2021_Cost_Allocation_Model_BHI_Revised.

8-Staff-69

Retail Transmission Service Rates

Ref: RTSR Model, Tab 3. RRR Data: Tab 5: Historic Wholesale
EB-2019-0023 Rate Generator Model Tab: 4. Billing Det. For Def-Var, Tab: 12: Historic Wholesale

Preamble:

The historic Wholesale and Retail volumes are provided as follows.

	EB-2019-0023	RTSR Model	Change
Wholesale			
Network	3,312,588 kW	3,070,440 kW	-7.3%
Line Connection	3,466,393 kW	3,322,463 kW	-4.2%
Transformation Connection	3,466,393 kW	3,322,463 kW	-4.2%
Retail			
Residential	535,270,676 kWh	535,270,676 kWh	-
General Service < 50 kW	173,151,275 kWh	173,151,275 kWh	-
General Service 50 – 4,999 kW	2,378,408 kW	2,378,408 kW	-
Unmetered Scattered Load	3,138,760 kWh	3,138,760 kWh	-
Street Light	20,571 kW	20,571 kW	-

Wholesale volumes have decreased while Retail volumes are the same as those in the previous application.

Question(s):

a) Please confirm that the retail quantities used in both EB-2019-0023, and the current application reflect the historic actual quantities from 2018.

b) Please ensure that the RTSR model is updated with 2019 retail quantities.

Response:

a) BHI confirms that the retail quantities used in both EB-2019-0023, and the current application reflect the historic actual quantities from 2018.

b) BHI provides an updated RTSR model with 2019 retail quantities, attached as Attachment_RTSR_Workform_BHI_Revised.

8-Staff-70

Loss Factors

Ref: OEB Appendix 2-R Loss Factors
EB-2016-0059 Rate Generator Model Tab: 4. Billing Det. For Def-Var
EB-2017-0029 Rate Generator Model Tab: 4. Billing Det. For Def-Var
EB-2018-0021 Rate Generator Model Tab: 4. Billing Det. For Def-Var
EB-2019-0023 Rate Generator Model Tab: 4. Billing Det. For Def-Var

Preamble:

The historic retail volumes (kWh) per the RTSR models and Appendix 2-R are as follows:

	2015	**2016**	**2017**	**2018**
Appendix 2-R - Retail	1,616,124,204	1,641,753,762	1,557,033,292	1,596,763,923
RTSR - Retail				
Residential	529,430,951	543,441,721	499,660,804	535,270,676
General Service < 50 kW	168,383,559	168,159,643	165,968,773	173,151,275
General Service 50 – 4,999 kW	901,690,816	913,512,381	878,667,071	878,675,189
Unmetered Scattered Load	3,091,043	3,115,068	3,130,312	3,138,760
Street Light	9,918,768	9,945,983	9,606,332	7,400,916
Total	1,612,515,137	1,638,174,796	1,557,033,292	1,597,636,816

While the 2017 retail volumes in Appendix 2-R match those from the EB-2018-0021, in the remainder of the years, the Appendix 2-R values do not match.

The proposed secondary loss factor of 1.0382 reflects an increase from the approved secondary loss factor of 1.0373.

Question(s):

a) Please reconcile the differences in retail quantities vs the amounts that had been filed in IRM rate cases.

b) Please explain the cause of the increase in loss factor.

Response:

a) The differences in the retail quantities in Appendix 2-R as compared to the amounts previously filed in BHI's IRM rate cases are due to RRR Revisions that were filed after the IRM rate applications. For 2015 and 2016 a RRR revision was filed on July 3, 2018 for 2.1.5.3 Supply and Delivery Information and for 2018 a RRR revision was filed on June 30, 2020 for 2.1.5.3 Supply and Delivery Information and 2.1.5.4 Demand and Revenue information. The 2.1.5.4 Demand and Revenue information for 2015 and 2016 should have been revised at the same time as the update to 2.1.5.3 Supply and Delivery information for 2015 and 2016 as the Delivery should reconcile to the Demand.

Table 1 below provides the Retail kWh broken down by rate class for each of 2015, 2016, and 2018 that reconcile to the Appendix 2-R Retail and to the RRR filings.

Table 1

Customer Rate Class	2015	2016	2018
Residential	530,678,450	544,630,435	535,270,676
G/S < 50kW	169,740,595	169,481,089	173,151,275
G/S > 50kW	902,695,348	914,581,187	878,675,189
USL	3,091,043	3,115,068	3,138,760
Street Lighting	9,918,768	9,945,983	6,528,023
Total	**1,616,124,204**	**1,641,753,762**	**1,596,763,923**
RRR Revision Dates	**July 3, 2018**	**July 3, 2018**	**June 30, 2020**

b) BHI's distribution network is a combination of three distinct voltage systems – 27.6kV, 13.8kV and 4.16kV. Distribution losses are different on each of the three voltage systems, and are the highest on the 4.16kV system. The combined overall loss rate across BHI's distribution network will vary year to year based on the percentage of energy delivered to customers through each voltage system.

8-Staff-71

Pole Attachment Charges
Ref: Exhibit 8, page 15

Preamble:

BHI states that its "existing Tariff of Rates and Charges issued April 16, 2020 does not specify the charge applicable to non-carriers and as such, BHI proposes to add this line item on its Tariff of Rates and Charges."

Question(s):

a) Please confirm Burlington Hydro's definition of what type of attachments would qualify as "carriers" vs "non-carriers".

b) How many attachments does Burlington Hydro have of each type, "carriers" and "non-carriers"?

Response:

a) Please refer to BHI's response to 8.0-VECC-76 a) for BHI's definition of what type of attachments would qualify as "carriers" versus "non-carriers".

b) Table 1 provides the number of attachments by each type, carriers and non-carriers.

Table 1

Pole Attachment Revenue	# of Attachments
Carrier (pole) - owed to BHI	11,199
Non-Carrier (pole)	5,126
Total	**16,325**
Carrier (pole) - BHI owes	(2,140)
Carrier - Other (Strands)	2,244
Carrier - Other (km of Duct)	1,000

9-Staff-72

Account 1575 IFRS-CGAAP Transitional PP&E Amounts
Ref 1: Exhibit 9, pages 17 – 19
Ref 2: Attachment 2 Chapter 2 Appendices, Tab 2-BA Fixed Assets Continuity Schedule

Preamble:

With respect to Account 1575 IFRS-CGAAP Transitional PP&E Amounts, BHI states that:
BHI is rebasing under IFRS for the first time in this Application. BHI has used Account 1575 IFRS CGAAP Transitional PP&E amounts ("Account 1575"), to record the financial differences arising from the transition to IFRS, regarding disposition to PP&E. Under IFRS, retirement of assets (pool of like assets) must be recorded each year, whereas under CGAAP no such adjustment was required.

This account therefore, represents the cumulative amounts for the losses on de- recognition of assets accumulated since the transition to IFRS. The loss on de-recognition principally relates to poles, meters and transformers requiring replacement before the end of their useful lives and have been disposed of before they were fully amortized.

BHI provides the following table which shows the breakdown of the losses by year:

Table 7 – Summary of Losses on De-recognition of Assets

Year	Gross Assets	Accum Deprn	Amount
2014 Actual[1]			$82,451
2015 Actual	($308,247)	$169,948	$55,848
2016 Actual	($61,953)	$28,932	$33,021
2017 Actual	($80,067)	$58,667	$21,400
2018 Actual	($751,471)	$419,336	$332,135
2019 Actual	($192,142)	$121,880	$70,262
Total to December 31, 2019	**($1,393,879)**	**$798,763**	**$595,117**
2020 Bridge Year	($382,456)	$256,787	$125,669
2021 Test Year (4 months)	($84,206)	$56,537	$27,669
Total to April 30, 2021	**($1,860,541)**	**$1,112,087**	**$748,454**
Rate of Return			5.41%
Total Return			**$81,007**
Total Amount for Disposition			**$829,462**

1. 2014 recorded in 2015

BHI states that “The 2020 Bridge Year and 2021 Test Year forecast losses of $125,669 and $27,669 respectively, were estimated based on BHI’s historical experience from 2014 to June 30, 2020”.

OEB staff has compiled the following table for the 2018 net book values of the disposed poles, line transformers and meters and notes that majority of the 2018 disposal is related to the meters:

OEB Account	Description	Disposals - Cost	Disposals - Accumulated Depreciation	Net Book Value of Disposed Assets (Calculated)
1830	Poles, Towers & Fixtures	-$ 13,488	$ 5,602	-$ 7,886
1850	Line Transformers	-$ 88,445	$ 55,036	-$ 33,408
1860	Meters	-$ 649,928	$ 358,427	-$ 291,501
	Total (Calculated)	**-$ 751,861**	**$ 419,066**	**-$ 332,795**

Question(s):

a) Please confirm the table compiled by OEB staff above.

b) Please provide additional details on the disposition of meters in the net book value amount of $291,501 in 2018.

c) Please explain how the 2020 Bridge Year and 2021 Test Year forecast losses of $125,669 and $27,669 were estimated based on BHI’s historical experience.

d) Please provide the actual unaudited loss recorded in 2020.

<u>Response:</u>

a) The table compiled by OEB Staff includes other disposal amounts in addition to the disposals relating to Account 1575. Please see BHI’s response to 2-Staff-32 b) for a reconciliation. Table 1 below identifies only the disposal amounts reported in Account 1575, by USoA for 2018.

Table 1

USoA	Description	Disposals Cost	Disposals - Accumulated Depreciation	Net Book Value of Disposed Assets
1830	Poles, Towers, and Fixtures	($10,930)	$4,906	($6,024)
1835	OH Conductors and Devices	($5,708)	$2,659	($3,049)
1845	UG Conductors and Devices	($232)	$93	($139)
1850	Line Transfomers	($84,673)	$53,250	($31,423)
1861	Meters	($649,928)	$358,427	($291,500)
Total		**($751,471)**	**$419,336**	**($332,135)**

b) The disposition of meters in 2018 captured scrap disposals of meters for the years 2011 through to 2018.

c) The 2020 Bridge Year forecast loss of $125,669 for scrap disposals of meters and transformers was derived using information available at the time of filing the Application. The 2021 Test Year forecast loss of $27,669 was derived using the 2020 Bridge Year forecast loss of $125,669 less an estimated loss of $98,000 for transformer and meter scrap disposals for the period from May 1 to December 31, 2021.

d) 2020 actual data is not available because BHI's year end processing is not complete.

9-Staff-73

Account 1508 Other Regulatory Assets - Deferred IFRS Transition Costs
Ref 1: Exhibit 9, pages 24 and 25
Ref 2: BHI's EDDVAR Continuity Schedule filed in 2014 CoS settlement, dated May 6, 2014

Preamble:

BHI is requesting the recovery of $328,603 in costs incurred for the IFRS transition that was recorded in a sub-account under Account 1508. BHI states that:

BHI has utilized this sub account to record one-time administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates. BHI has not previously applied to the OEB for approval to include any IFRS transition costs in distribution rates.

BHI provides the following table showing the breakdown of the IFRS transition costs:

Table 11 – IFRS Transition Costs

Description	pre-2014	2015	2016	Total
Professional accounting fees	$127,488	$11,937	$40,000	$179,425
Professional legal fees	$0			$0
Salaries, wages and benefits of staff added to support the transition to IFRS	$94,377			$94,377
Associated staff training and development costs	$1,196			$1,196
Costs related to system upgrades, or replacements or changes				$0
Other	$13,078			$13,078
Total Principal Amount	**$236,139**	**$11,937**	**$40,000**	**$288,076**
Total Carrying Charges				**$40,527**
Total Proposed for Disposition				**$328,603**

BHI states that "The costs incurred in 2015 and 2016 related to the development of IFRS and CGAAP financial statements and note disclosures". BHI also explains that the salaries of $95,377 represents the cost associated with a temporary staff because "Temporary staff was hired to assist with the transition to IFRS in 2009 and 2010".

From the review of the DVA continuity scheduled filed in BHI's settlement dated May 6, 2014, OEB staff notes that BHI did not input any figures in the Account 1508 sub-account Deferred IFRS Transition Costs.

Question(s):

a) Please confirm the OEB staff's observation above and explain whether BHI had disclosed the IFRS transitional costs in the 2014 rate application.

b) Please explain why BHI did not input any figures in Account 1508 sub-account IFRS transition Costs in the closing 2014 DVA continuity schedule, given that the majority of pre-2014 costs listed in the table above would have been available at that time?

c) Please provide additional detail regarding the nature of work that the temporary staff were assigned.

Response:

a) BHI confirms that it did not enter any figures in the Account 1508 sub-account Deferred transition costs in the DVA continuity schedule filed May 6, 2014. This was an oversight/error on BHI's part. The balance was not included for disposition in the application as these costs were not eligible for disposal until BHI had fully transitioned / adopted IFRS, which occurred in 2015. Nonetheless this Account should have been included on Tab "2. 2013 Continuity schedule" under "The following is not included in the total claim but are included on a memo basis" BHI did disclose that there would be IFRS transitional costs in its 2014 COS rate application for which it would be seeking future disposition at Exhibit 9, Tab 1, Schedule 4, page 1 of 3.

b) Please refer to part a) above.

c) Temporary staff was hired to perform a detailed analysis of the chart of accounts and general ledger details for the transition to IFRS. The analysis provided a basis to identify and allocate eligible/directly attributable expenses to capital based on the nature of the expenses. The analysis was reviewed and approved by KPMG.

9-Staff-74

Account 1508 Other Regulatory Assets - Pole Attachment Charge Revenues Variance
Ref 1: Exhibit 9, pages 25 and 26

Preamble:

BHI is requesting to dispose $(727,884) in Account 1508 sub-account Pole Attachment Charge Revenues Variance. BHI states that "BHI has forecast activity up until April 30, 2021 prior to the rebasing of rates in May 1, 2021. There will be no additional principal balances after April 30, 2021".

BHI provides the following table showing the breakdown of the variances by year:

Table 12 – Pole Attachment Charge Revenues Variance

Period	Principal	Carrying Charges	Amount
Total to December 31, 2019	($316,414)	($1,688)	($318,101)
2020 Bridge Year	($302,190)	($5,632)	($307,822)
2021 Test Year (4 months)	($100,730)	($1,230)	($101,960)
Total to April 30, 2021	**($719,334)**	**($8,550)**	**($727,884)**

Question(s):

a) Please fill out the table below for the pole attachment revenue variances by year since September 1, 2018 (prorating for four months in 2018 as needed) and compare to the principal balance recorded in the account:

Year	# of Pole Attachments	OEB-Approved Pole Attachment Rate	Rate approved in the last CoS proceeding	Calculated Pole Attachment Revenue Variance $	Principal Balance recorded in Account 1508	Difference

Please explain any differences.

b) Please explain whether the number of pole attachments in 2020 is based on an actual, rather than estimated, figure. If not, please update the figure to actuals and recalculate the 2020 revenue variance.

c) Please provide the assumption(s) used as the basis for the forecasted number of pole attachments in 2021 in the table above.

Response:

a) BHI provides Table 1 below to compare the pole attachment revenue variance for the period September 1, 2018 to April 30, 2021 to the principal balance recorded in Account 1508 Other Regulatory Assets - Pole Attachment Charge Revenues Variance.

Table 1

Period	# of Pole Attachments	OEB-Approved Pole Attachment Rate	Rate Approved in Last COS Proceeding	Calculated Pole Attachment Revenue Variance	Principal Balance Recorded in Account 1508	Difference
Sept. 1 to Dec.31, 2018	16,265	$28.09	$22.35	$31,120		
	(2,140)	$34.42	$27.39	($5,015)		
				$26,106	$26,106	-
Jan. 1 to Dec.31, 2019	16,265	$43.63	$22.35	$346,119		
	(2,140)	$53.47	$27.39	($55,811)		
				$290,308	$290,308	-
Jan. 1 to Dec.31, 2020	16,265	$44.50	$22.35	$360,270		
	(2,140)	$54.53	$27.39	($58,080)		
				$302,190	$302,190	-
Jan. 1 to Apr.30, 2021	16,265	$44.50	$22.35	$120,090		
	(2,140)	$54.53	$27.39	($19,360)		
				$100,730	$100,730	-
Total Variance Account 1508 Forecasted to April 30, 2021				**$719,334**	**$719,334**	**-**

b) The 2020 pole attachment revenue has been calculated using the actual number of pole attachments invoiced to the carriers and non-carriers.

c) The number of pole attachments used in the revenue calculation did not change for the period 2014 to 2020. BHI does not foresee a change in these pole attachment numbers for 2021 and has calculated the 2021 forecasted pole attachment revenue using the 2020 count.

9-Staff-75

Account 1508 Other Regulatory Assets - Monthly Billing Incremental Costs
Ref 1: Decision and Order EB-2016-0384 & EB-2016-0059, pages 15 and 16
Ref 2: Exhibit 9, pages 27 - 29

Preamble:

On page 15 of the decision and order for EB-2016-0384 & EB-2016-0059, BHI stated that:

With respect to materiality, Burlington Hydro estimated that the annual incremental costs associated with the transition to monthly billing would be $335,000. These estimated costs include incremental billing costs, incremental exceptions processing costs and incremental call centre costs. Burlington Hydro has also estimated that there would be potential benefits associated with transitioning to monthly billing as follows:

- reductions in bad debt expense of $79,000,
- avoided costs of transition to e-billing of $54,000, and
- avoided call centre costs of $9,500

Burlington Hydro expects that the total offset to costs would be $142,500 for a net increase in costs of $192,500. The net incremental cost of $192,500 is in excess of Burlington Hydro's materiality threshold of approximately $145,000 as determined from its OEB-approved 2014 cost of service application. Burlington Hydro noted that it is actively monitoring its working capital position for impacts attributable to monthly billing its residential customers.

The OEB approved the establishment of this deferral account and stated that:

The deferral account will be used to record the incremental costs directly attributable to the transition to monthly billing. The associated offsetting benefits shall include but not be limited to reduction in bad debt expense, working capital allowance, avoided costs of transition to e-billing and other avoided costs.

In the current application, BHI is requesting to dispose of a principal balance of $851,261 plus carrying charges in Account 1508 sub-account Monthly Billing Incremental Costs and provides the breakdown of the costs as below:

DR/(CR)	2017	2018	2019	2020 Bridge Year	2021 Test Year	Total
Postage/Mail Service/Stationery Costs	$339,341	$256,409	$238,819			$834,569
Working Capital Allowance Savings	($44,875)	($26,592)	($18,543)			($90,011)
Revenue Requirement [1]			$70,073			$70,073
Sub-Total to be Recovered from Customers	**$294,466**	**$229,817**	**$290,349**	**$0**	**$0**	**$814,631**
Carrying Charges	$1,366	$7,700	$14,871	$11,165	$1,527	$36,629
Total to be Recovered from Customers	**$295,832**	**$237,517**	**$305,220**	**$11,165**	**$1,527**	**$851,260**

With respect to the postage/mail service/stationary costs, BHI states that:

BHI determined incremental costs by multiplying the number of additional paper bills generated by the adoption of monthly billing by the per invoice postage, mail service and stationery costs.

The savings from any transition to e-billing is factored into this number by using the number of paper bills only.

With respect to the 2019 revenue requirement impact of $70,073, BHI states that:

BHI incurred $139,126 in capital expenditures to install software in its legacy Customer Information System ("CIS") to transition its residential customers from bi-monthly billing to monthly billing. This expenditure was outside of the base upon which rates were set and as such BHI has included the revenue requirement associated with this expenditure in the deferral account.

Question(s):

a) Please explain why the actual net incremental costs in 2017 to 2019 (ranging from $229,817 to $294,466) are much higher than BHI's original estimate of the annual incremental cost $192,500, as stated in its 2017 rate application.

b) Please separate the postage/mail service/stationary costs in the table above into the costs and the savings from the transition to e-billing and provide the calculation for each category, showing the number of the bills and cost/saving per bill.

c) Please provide the calculation of the working capital allowance savings.

d) Please explain why there are no reduction of bad debt expenses and avoided call center costs included in the account, as originally estimated by BHI in 2017.

e) Please provide the basis/reference in BHI's 2017 decision and order that supports the inclusion of the revenue requirement on monthly billing software in the account.

Response:

a) The actual net incremental costs in 2017 to 2019 are higher than BHI's original estimate of $192,500, as stated in its 2017 IRM application[1] for the following reasons:

- Unanticipated one-time costs in 2017 associated with a 196% increase in accounting in collections as identified in Table 1 below; and
- BHI did not experience any reduction in bad debt expense or avoided call centre costs as originally anticipated.

b) In preparation of the response to this interrogatory, BHI realized that the 2017 Postage/Mail/Stationery costs included other expenses not related to Postage/Mail/Stationery. BHI provides a revised Table 14 in Exhibit 9 below as Table 1.

Table 2 below separates the postage/mail service/stationary costs into the costs from the transition to monthly billing and the savings from the transition to e-billing and provides the calculation for each category, showing the number of the bills and cost/saving per bill.

However, when BHI determines the net costs associated with the transition to monthly billing, it does not calculate the costs from the transition to monthly billing separately from the savings from the transition to e-billing. Specifically, net costs are calculated by month, using the incremental number of paper bills that were issued as a result of the transition to monthly billing. Using this number inherently captures the savings as a result of the transition to e-billing. To provide the information requested in this interrogatory, BHI added the number of bills for the customers who transitioned to e-billing to the number of paper bills in order to separate costs from savings.

(2020 and 2021 Estimates are provided to satisfy BHI's responses to 9-SEC-35 e) and CCC-27)

[1] EB-2016-0384

Table 1 (revised Table 14, Exhibit 9)

DR/(CR)	2017	2018	2019	2020 Bridge Year	2021 Test Year	Total
Postage/Mail Service/Stationery Costs	$253,918	$256,409	$238,819			$749,147
Incremental Labour - Billing and Customer Service	$28,423					$28,423
Collection Activity [1]	$57,000					$57,000
Working Capital Allowance Savings	($44,875)	($26,592)	($18,543)			($90,011)
Revenue Requirement [2]			$70,073			$70,073
Sub-Total to be Recovered from Customers	**$294,466**	**$229,817**	**$290,349**	**$0**	**$0**	**$814,631**
Carrying Charges	$1,366	$7,700	$14,871	$11,165	$1,527	$36,629
Total to be Recovered from Customers	**$295,832**	**$237,517**	**$305,220**	**$11,165**	**$1,527**	**$851,260**

1. One-time incremental charges for collection activity - BHI experiences a 196% increase in accounts in collections because customers were not accustomed to paying their invoices on a monthly basis.

2. for RRR reporting BHI recorded the cumulative revenue requirement (from 2016 to 2019) in 2019

Table 2

Year	Paper Bills before Transition to e-billing			E-bills			Net Cost of Transition to Monthly Billing (as per Table 1 above for 2017-2019)
	Total # of Bills attributable to Monthly Billing	Total Cost per Paper Bill	Total Cost of Additional Bills (Monthly Billing)	Cumulative Paper Bills transitioned to E-bills	Total Avoided Cost per E-bill [1]	Savings due to Transition to E-billing	
	a	b	c = a x b	d	e	f = d x e	g = c + f
2017	257,846	$1.03	$264,563	(10,374)	$1.03	($10,644)	**$253,918**
2018	288,255	$1.03	$296,650	(39,102)	$1.03	($40,241)	**$256,409**
2019	303,600	$1.02	$309,884	(69,624)	$1.02	($71,065)	**$238,819**
Total	**849,701**		$871,097	**(119,100)**		**($121,950)**	**$749,146**
2020 Estimate [1]	316,944	$1.11	$350,540	(89,406)	$1.07	($95,307)	**$255,233**
2021 Estimate [1]	325,315	$1.13	$366,995	(103,020)	$1.09	($112,098)	**$254,896**

1. Total avoided cost per e-bill in 2020/2021 = cost per paper bill less incremental cost to issue e-bill of $0.04/bill

c) BHI provides the calculation of the working capital allowance savings (i.e., interest savings) in Table 3 below.

Table 3

Description	Formula	2016 (Base)	2017	2018	2019	Total
Days in Year	a	366	365	365	365	
DSO (actual)	b	74.08	65.29	68.79	70.33	
Sales of electricity (actual for 2016; held constant for 2017-2019)	c	$224,282,685	$224,282,685	$224,282,685	$224,282,685	
Sales of electricity (daily)	d = a / c	$612,794	$614,473	$614,473	$614,473	
Average A/R[1] (actual for 2016; calculated for 2017-2019)	e = d x b	$45,396,140	$40,116,689	$42,267,619	$43,214,640	
A/R 2016 level (held constant for 2017-2019)	f	$45,396,140	$45,396,140	$45,396,140	$45,396,140	
Actual A/R Higher/(Lower) vs. 2016	g = e - f	$0	($5,279,451)	($3,128,521)	($2,181,500)	
2016 Interest Rate on Cash Balances	h	0.85%	0.85%	0.85%	0.85%	
Interest Savings	**I = g x h**	**$0**	**($44,875)**	**($26,592)**	**($18,543)**	**($90,011)**

1. Average A/R calculated using actual DSO for the year with electricity sales held constant at 2016 levels to isolate impact of monthly billing change only

d) BHI has not experienced a reduction in bad debt expenses as originally forecast due to the transition to monthly billing. This is consistent with the experience of Hydro Ottawa Limited who identified that one year after transitioning to monthly billing there was "*no evidence to date for any material reduction in collection costs and bad debt*".[2] Furthermore, BHI call centre volumes have not decreased as originally forecasted with the migration to monthly billing. Conversely, they have increased in volume. Other inbound customer communications have also increased as identified in Table 4 below.

Table 4

Year	Calls	Correspondence
2017	46,951	9,740
2018	49,037	11,570
2019	46,810	9,942
2020	59,966	16,985

[2] EB-2014-0198, p 2

e) BHI recognizes that the OEB had indicated in its *Notice of Amendment to a Code, Amendments to the Distribution System Code* dated April 15, 2015, that the OEB had stated "*any deferral account would generally be for incremental administration costs. Prudently incurred capital expenditures would be included in rate base at the next cost of service application*".[3]

However, BHI is in a unique situation in that it is implementing a new Customer Information System ("CIS") in Q2, 2021 at which time the investment in monthly billing software in its legacy CIS will be fully depreciated (the software will no longer be used). Consequently, BHI will not have the opportunity to recover these capital expenditures at the next cost of service application (i.e., this Application). As such, BHI respectfully requests that it be permitted to include the revenue requirement on monthly billing software in Account 1508 sub-account Monthly Billing Incremental Costs.

[3] EB-2014-0198, p 3

9-Staff-76

Account 1508 Other Regulatory Assets - OEB Cost Assessment Variance
Ref 1: Exhibit 9, pages 30 and 31

Preamble:

BHI is requesting to dispose of $452,018 in Account 1508 sub-account OEB Cost Assessment Variance and states that “BHI has forecast activity up until April 30, 2021 prior to the rebasing of rates in May 1, 2021 and as such requests that this account be discontinued”.

BHI provides the breakdown of the costs by year in the following table:

Table 16 – OEB Cost Assessment Variance

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

Question(s):

a) Please update the 2020 cost to the actual billed amount, if available. If not, please explain how the forecast is derived.

b) Please explain how the 2021 forecasted cost is derived.

Response:

a) The 2020 Bridge Year cost of $284,735 is the actual billed amount. The OEB bills their cost assessment three months in advance on a quarterly basis so this amount was known prior to filing this Application.

b) The 2021 forecast amount was derived based on an estimated quarterly invoice of $71,000 in the 2021 Test Year. The variance account is in effect for four months until April 30, 2021. As such, the forecasted amount of $94,667 is equal to $71,000/3 X 4. (BHI has received the invoice for Q1, 2021 since the filing of this Application – the invoice amount for three months is $70,564).

9-Staff-77

Account 1508 Other Regulatory Assets - Collection Charges Lost Revenue
Ref 1: Decision and Order EB-2019-0179, pages 31 and 32
Ref 2: Exhibit 9, pages 31 and 32

Preamble:

BHI provides the following cost breakdown that is booked in this account:

Table 17 – Collection Charges Lost Revenue

Description	Jul 1/2019 - Dec 31/2019
# of Collection Notices issued	9,925
$ Charge/Collection notice	$30
Total Collection Charges Lost Revenue	$297,750
Savings from Process Changes	($22,400)
Total Principal Amount Recorded in DVA	**$275,350**
Carrying Charges	$5,548
Total Amount Requested for Disposition	**$280,898**

BHI states that "BHI confirms that it changed its process for field collection services to (i) move to an hourly versus piece rate and (ii) eliminate hand delivery in order to offset the lost revenue as a result of the elimination of the collection of account charge".

Question(s):

a) Please explain why there is no substantial saving from the removal of the collection charges activity and provide the calculation for the savings from process changes of $22,400.

Response:

a) There was no removal of "collection charges activity". The OEB prohibited LDCs from charging for the issuance of a collection notice,[1] which results in a material decrease in other revenue, not in costs associated with collections activity. BHI continues the process of collections and, with the exception of the changes in process identified on lines 4-8 of

[1] Exhibit 9, page 31-32

page 33 of Exhibit 9, BHI's collection processes have not changed. Collection activity continues to be required on customer accounts; recovery of overdue amounts continues to be required; and collection notices are still sent to customers who are in arrears with their payments.

The cost savings of the $22,400 are a result of two process changes as follows:

i. BHI stopped hand delivery of its collection notice and now delivers using Canada Post; and
ii. BHI changed the pricing structure of its Field Services Collector contract and now pays a flat rate instead of a by piece rate.

The difference in costs associated with issuing collections notices by switching from a by piece rate to a flat rate and ceasing hand delivery is $53,500 for six months. (BHI continues to incur costs associated with the creation of the collection notice). Incremental costs associated with mailing collections notices through Canada Post is $31,100 for six months. This results in a net savings of $22,400 for six months. Full year savings are $44,800.

9-Staff-78

Account 1508 Incremental Capital Module - Tremaine TS CCRA and Account 1508 Incremental Capital Module - Tremaine TS CCRA
Ref 1: Exhibit 2, pages 80-82
Ref 2: Exhibit 9, page 33
Ref 3: Attachment 18, DVA Continuity Schedule

Preamble:

BHI requests to dispose of $(175,855) in Account ICM – Tremaine TS CCRA and provides the following breakdown of the variance:

Table 80 – Comparison of Revenue Requirement to Revenue Collected from Customers

Description	Amount
Annual Revenue Requirement (2019 as per EB-2019-0023)	$42,632
Annual Revenue Requirement (2020)	$42,894
Average Annual Revenue Requirement over Recovery Period	**$42,719**
Months of Recovery	24
Total Revenue Requirement	$85,439
Total Rate Rider Collected	$260,566
(Over)/Under Collection	**($175,127)**
Carrying Charges (Due to)/Due from Ratepayers	($2,727)
Amount (Due to)/Due from Ratepayers	**($177,855)**

BHI requests to dispose $7,934 in Account 1508 Incremental Capital Module - Tremaine TS CCRA. In Exhibit 2, BHI states that “BHI proposes to dispose of the amount due to ratepayers via a one-year rate rider” for both ICM accounts.

OEB staff notes, from the review of the DVA continuity schedule, that both ICM accounts are includes as part of Group 2 accounts disposing over the two-year period.

Question(s):

a) Please clarify whether the proposed disposition for these two ICM accounts is one year or two years.

b) Please explain what has led to such a substantial over-collection for this project.

c) Please provide the calculation for the total rate rider collected of $260,566 showing the rate riders per the rate classes and the billing determinants.

Response:

a) BHI confirms that the proposed disposition for these two ICM amounts is two years.

b) The amount approved for disposition in BHI's 2019 IRM rate application for the Tremaine TS CCRA true-up was $3.567MM based on the best estimates provided by Hydro One at the time.[1] A Rate Rider for Recovery of Incremental Capital Project 1 was based on this amount, effective until BHI's next rebasing application which was scheduled for 2021. After the 2019 IRM proceeding, BHI requested Hydro One revisit the calculation because it was not in agreement with the allocation of load between transformer stations. Based on this request Hydro One finalized the true-up amounts payable by BHI to be $0.568MM. Since the rate rider was calculated to recover the revenue requirement associated with a $3.567MM capital investment, continuing the rate rider until BHI's next rebasing would result in a significant over collection from customers. BHI requested, and was approved, to discontinue the rate rider effective May 1, 2020,[2]; and the rate rider remained in effect for one year only. However, during that time, there was still a substantial overcollection as BHI collected $260,566 based on a capital expenditure of $3,567MM. Based on the actual true-up amount of $0.568MM, BHI only needed to collect $85,439 from customers until its next rebasing.[3]

c) Table 1 provides the calculation of the total rate rider collected by rate class and billing determinant.

Table 1

Rate Class	Billing Determinant	ICM Rate Rider $ Collected	Totals
Residential	Mthly S/C	$162,357	$162,357
GS < 50kW	Mthly S/C	$15,100	$31,337
	kWh	$16,237	
GS > 50kW	Mthly S/C	$6,211	$65,923
	kW	$59,712	
Unmetered Scattered Load	Mthly S/C	$21	$336
	kWh	$314	
Street Lighting	Mthly S/C	$0	$613
	kW	$613	
Total ICM Project 1 Rate Rider $ Collected			**$260,566**

[1] EB-2018-0021 Decision and Rate Order, March 28, 2019, p 17
[2] EB-2019-0023, Decision and Rate Order, April 16, 2020, p 27-28
[3] Ibid, p 27

9-Staff-79

Account 1592 PILs and Tax Variances – CCA Changes
Ref 1: Exhibit 9, pages 35 and 36
Ref 2: the OEB's Letter "Accounting Direction Regarding Bill C-97", July 25, 2019
Ref 3: Exhibit 4, Appendix E 2019 Tax Return

Preamble:

BHI is requesting to dispose $(192,554) to the ratepayers for the CCA changes. The amount represents 50% sharing of the total principal balances in 2018 and 2019 of $376,460 plus the carrying charges of $4,323 as shown in the table below:

Table 18 – Impact to Revenue Requirement of CCA Changes

Description	2018	2019	Total
Prior CCA	$444,452	$1,173,802	$1,618,254
Accelerated CCA	$787,863	$1,874,539	$2,662,402
Difference in CCA	($343,411)	($700,737)	($1,044,148)
Tax Impact @ 26.5%	($91,004)	($185,694)	($276,698)
Grossed up PILs	**($123,815)**	**($252,645)**	**($376,460)**
Remove 50% of Principal Amount			$188,230
Add Carrying Charges			($4,323)
Total Payable to Ratepayers			**($192,553)**

The OEB's July 25, 2019 letter Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance states that:

The OEB expects Utilities to record the impacts of CCA rule changes in the appropriate account (Account 1592 - PILs and Tax Variances and similar accounts for natural gas utilities and OPG) for the period November 21, 2018 until the effective date of the Utility's next cost-based rate order. For the purposes of increased transparency, the OEB is establishing a separate subaccount of Account 1592 - PILs and Tax Variances – CCA Changes specifically for the purposes of tracking the impact of changes in CCA rules.

Schedule 8 of PILs Wordform shows the 2019 accelerated CCA (per column 17) is $10,259,615. OEB staff notes that the 2019 accelerated CCA per the table above is $1,874,539.

Question(s):

a) Please clarify that the "Prior CCA" in the table above refers to the CCA under the half-year legacy rule prior to the implementation of the Accelerated CCA rules.

b) Please provide the calculations for the 2018 and 2019 “Prior CCA” figures in the table.

c) Please provide a copy of Schedule 8 in 2018 tax return and reconcile that with the accelerated CCA figure above.

d) Please explain the discrepancy noted between the 2019 accelerated CCA on Schedule 8 of the tax return and the figure in the table.

e) Please explain whether the CCAs are calculated using the approved capital expenditures in the last cost of service proceeding or the actual capital expenditures in the respective periods.

   i) If BHI has used the actual capital expenditures to calculate the CCA differences, please explain the rationale of this approach and please also provide the calculation of the CCA differences in 2020 and four months in 2021 using the forecasted capital expenditures.
   ii) Please provide the CCA differences calculation from 2018 to 2020 using the approved capital expenditures in BHI’s last cost of service proceeding.
   iii) Please compare the CCA differences using the actual capital expenditures and the approved capital expenditures in BHI’s last cost of service proceeding.

f) Is BHI aware of any other circumstances in which the OEB approved refunding 50% of the AIIP impacts to ratepayers? If so, please provide references to the applicable evidence.

Response:

a) BHI confirms that the “Prior CCA” in Table 18 of Exhibit 9 refers to the CCA under the half-year legacy rule prior to the implementation of the Accelerated CCA rules.

b) BHI provides the calculations for the 2018 and 2019 “Prior CCA” figures as Appendix E: 9-Staff-79 b); in addition to the calculations for 2020 to satisfy interrogatory 9-SEC-36 b).

c) BHI provides a copy of the Schedule 8 from the 2018 PILs tax return as Appendix F: 9-Staff-79 c). A reconciliation to the 2018 PILs tax return would not be appropriate as the 2018 PILs tax return is based on CCA calculated on the actual 2018 additions as opposed to the additions in BHI’s previous rate-setting Application. The additions in BHI’s previous rate setting Application, and the corresponding CCA, is what is included in BHI’s rates.

The AIIP calculation as provided above and in Appendix F: 9-Staff-79 c) compares the Test Year additions from the last rate-setting Application, using the "half-year legacy rules", to the amount of CCA that would otherwise have been calculated if the accelerated CCA rules were applied in the last rate-setting Application. The actual percentage of additions in 2018 that were eligible for AIIP in 2018 was applied to the Test Year Additions, to most accurately depict the pro-rata portion of Test Year additions that qualified for AIIP in 2018. This calculation is provided in Appendix E: 9-Staff-79 b).

d) Reconciling the CCA on the 2019 PILS Tax Return to the calculation in Appendix E: 9-Staff-79 b) would not be appropriate as the calculation in Appendix E: 9-Staff-79 b) determines the amount of CCA on additions that would have been included in the last rate setting application had BHI calculated CCA using the new Accelerated CCA rules, as opposed to the "old legacy half-year rules". The actual CCA as calculated on the 2019 PILS Tax Return is based on actual additions in 2019, not the Test Year additions, and is therefore an inappropriate comparison.

e) The CCA in Appendix E: 9-Staff-79 b) is calculated using the approved capital expenditures in its last cost of service proceeding.

    i. BHI has not used the actual capital expenditures to calculate the CCA differences.

    ii. This calculation is provided in Appendix E: 9-Staff-79 b).

    iii. This is not applicable as BHI did not use actual capital expenditures to calculate the CCA differences. BHI used the capital expenditures as approved in its last cost of service proceeding.

f) BHI is not aware, to the best of its knowledge, of any other circumstances in which the OEB approved refunding 50% of the AIIP impacts to ratepayers.

9-Staff-80

Interim Disposition of Group 1 DVAs
Ref 1: Exhibit 9, page 38

Preamble:

BHI states that:

In BHI's 2020 IRM application (EB-2019-0023), the OEB approved BHI's proposal to dispose of its Group 1 account balances on an interim basis given that it was implementing new processes with its new CIS. BHI committed to address two issues with its calculation of its Group 1 DVA balances during that time:

i) not recording different rates for RPP and non-RPP cost of power; and
ii) not re-estimating unbilled revenue at the end of each month;

BHI has not implemented its CIS as of the date of filing this Application. As such it is unable to address the two issues identified above and these continue to be deviations from the OEB's Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment. As such, BHI proposes to dispose of its Group 1 deferral and variance account balances in this Application on an interim basis until such time as it can finalize its processes for the Commodity Pass-Through Variance Accounts using its new CIS.

Question(s):

a) Please confirm that BHI is not requesting final disposition of its 2018 Group 1 DVA balances, previously disposed on an interim basis, in this application.

b) Please provide the status of the CIS implementation and the anticipated process change date for the commodity pass-through accounts.

<u>Response:</u>

a) BHI confirms that it is not requesting final disposition of its 2018 Group 1 DVA balances, previously disposed on an interim basis, in this Application.

b) BHI expects to go live with its new CIS by June 30, 2021. The process change date for the commodity pass-through accounts is expected to be in Q3, 2020.

9-Staff-81

GA Analysis Workform
Ref 1: Attachment 23, GA Analysis Workform

Preamble:

On Tab "GA 2019" of the GA Analysis Workform, OEB staff notes that BHI entered an amount of $336,022 in Note 5 Reconciling Item #4 Differences in actual system losses and billed TLFs.

Question(s):

a) Please provide the calculation for the line loss difference related to the GA of $336,022.

Response:

a) BHI provides the calculation used to quantify Reconciling Item #4 Differences in actual system losses and billed TLFs in Table 1 below.

Table 1

2019	Formula	Amount
kWh IESO per workform	A	584,003,302
Actual Loss	B = L	4.1036%
kWh Delivered	C = A*(1-B)	560,037,919
Billed Loss	D	3.7300%
kWh Billed	E = C*(1+D)	580,927,334
kWh differential	F = E-A	(3,075,968)
Average GA Rate/kWh	G	$0.10924
Revenue Over/(Under) Stated in Account 1589	**H = F*G**	**($336,022)**
2019 Losses as per RRRs	**Formula**	**Amount**
Supply (expense)	I	1,595,966,604
Delivery (revenue)	J	1,530,473,908
Losses	K = I-J	65,492,696
Losses %	L = K/I	4.1036%

9-Staff-82

Two Issues Related to the Commodity Accounts
Ref 1: 2020 IRM Decision and Order EB-2019-0023, pages 12 and 13

Preamble:

Page 12 of the 2020 IRM Decision and Order EB-2019-0023 states that:

> Burlington Hydro has the following four deviations from the accounting guidance: (i) not recording different rates for RPP and non-RPP cost of power; (ii) not re-estimating unbilled revenue at the end of each month; (iii) some of Burlington Hydro's data used for RPP settlement true-ups with the IESO (i.e. non-interval metered and retailer customers) are estimates; and (iv) in booking expense journal entries for Charge Type (CT) 1142 and CT 148 from the IESO invoice, Burlington Hydro uses a different approach than that required by the OEB, which is approach "a".[21]

The OEB stated that:

The OEB approves the disposition of a credit balance of $371,076 as of December 31, 2018, including interest projected to April 30, 2020 for Group 1 accounts on an interim basis. The OEB agrees with Burlington Hydro's proposal to dispose of balances on an interim basis given that it is implementing new processes with its new CIS. The OEB accepts Burlington Hydro's commitment to address the first two issues identified by OEB staff (rates to use for RPP and non-RPP and timing of unbilled revenue re-estimate) when the new CIS is implemented. **Burlington Hydro has stated that it addressed the third and fourth issues in 2019. This can be reviewed when the 2019 balances are filed for disposition** [emphasis added].

Question(s):

a) Please describe how the third and fourth issue identified in 2020 IRM proceeding have been resolved.

b) Please provide the associated evidence to show the resolution of the issues.

Response:

a) BHI described how it addressed the third and fourth deviations from the OEB's *Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589*[1] on pages 7-9 of its Reply Submission in its 2020 IRM proceeding.[2]

b) Please refer to Appendix G: 9-Staff-82 b) for the evidence related to the third issue and Appendix H: 9-Staff-82 b) for the evidence related to the fourth issue. (Charge Type 1142 has always been booked to USoA 1588 and as such this was never a deviation from OEB accounting policy).

[1] Accounting Procedures Handbook Update, February 21, 2019
[2] EB-2019-0023, February 14, 2020

APPENDIX A: 1-Staff-2

-----Original Message-----
From: Webmaster <Webmaster@oeb.ca>
Sent: Monday, November 23, 2020 11:47 AM
To: registrar <registrar@oeb.ca>
Subject: Letter of Comment - [redacted]

The Ontario Energy Board

-- Comment date --
2020-11-23

-- Case Number --
EB-2020-0007

-- Name --
Alex Hutchinson

-- Phone --
[redacted]

-- Company --

-- Address --
[redacted]

-- Comments --
Hi,

I am a bit confused by the increase. People are losing their jobs and we are most likely headed into another lockdown this winter but Hydro One wants to increase rates for residential properties in the Spring? That is a ballsy move right there.

Alex

Burlingtonhydro inc.

Attention: Alex Hutchinson
VIA EMAIL

December 1, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Mr. Hutchinson,

Thank you for your Letter of Comment submitted to the Ontario Energy Board with respect to the residential rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You mentioned in your letter that Hydro One wants to increase rates for residential properties in the spring. Burlington Hydro is responsible for the distribution of electricity in Burlington and the Application that we have filed relates to the rates that Burlington Hydro charges our customers to build, operate and maintain the electricity distribution system in the City of Burlington. Distribution rates account for approximately 26% of the entire electricity bill. Burlington Hydro is 100% owned by the City of Burlington.

You have also expressed concern that Burlington Hydro is proposing an increase to residential rates at this time. The proposed residential rate increase in May 2021 is the result of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations.

Burlington Hydro submits this type of application - a Cost of Service application - to the Ontario Energy Board once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in residential rates beyond inflation is required next year to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g. poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan. Attached is a brief summary of our Application to provide you with some more information.

The Ontario Energy Board will only approve an increase to distribution rates if Burlington Hydro can provide adequate evidence to support the capital and operating costs that are contributing to the increase. Various intervenor groups, made up of experts who act on behalf of customers, will also review the application and may challenge the proposed rate changes.

There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program (CEAP), the Ontario Electricity Support Program (OESP), the Low-Income Energy Assistance Program (LEAP) and the Affordability

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Fund Trust (AFT). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

In addition, eligible customers are now able to choose between Time-of Use and Tiered electricity rates, which make up 43% of the average residential electricity bill. These rates are set by the Ontario Energy Board (OEB) bi-annually. Depending on how and when you use electricity, changing your electricity price plan may save you money on your electricity bill. More information is available on our website at:
https://www.burlingtonhydro.com/billing/time-of-use-customer-choice-landing.html

Thank you again for your comments and please contact us with any further questions or concerns.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

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BURLINGTON HYDRO'S 2021- 2025 RATE APPLICATION

About BURLINGTON HYDRO

Burlington Hydro Inc. ("BHI") is a local distribution company serving approximately 68,000 residential and commercial customers in the City of Burlington. BHI is responsible for distributing power from the provincial transmission grid safely and reliably to homes and businesses across its service territory. The company is wholly owned by the City of Burlington.

BHI's 2021-2025 Business Plan

BHI has applied to the Ontario Energy Board for a change in the distribution rates that it charges its customers, effective May 1, 2021. The distribution rates are based on BHI's business plan, which includes capital investments (e.g. poles and wires) as well as operating expenses for day-to-day management of the company (e.g. customer service and outage response).

Between 2014 and 2020, BHI invested in replacing deteriorated distribution system assets such as wood poles and transformers in order to reduce the frequency and duration of unplanned outages. Capacity upgrades were made to accommodate growth in North East Burlington and vertical growth in downtown Burlington. Investments were made in new computer software systems, including BHI's Customer Information System which empowers customers with more self-service options and solutions to help manage and monitor energy use.

BHI developed its business plan based on information and input from internal engineering and technical experts, who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans. The plan also considers BHI's legal and statutory requirements as a regulated utility.

How Customers Informed BHI's Plans

BHI engaged customers throughout the development of its 2021-2025 business plan to inform and solicit feedback on the proposals being considered and associated outcomes expected. Between June 2019 and January 2020, BHI gathered feedback from close to 5,000 residential, small business and commercial customers through its customer engagement efforts.

BHI's Plan Delivers Outcomes to Customers

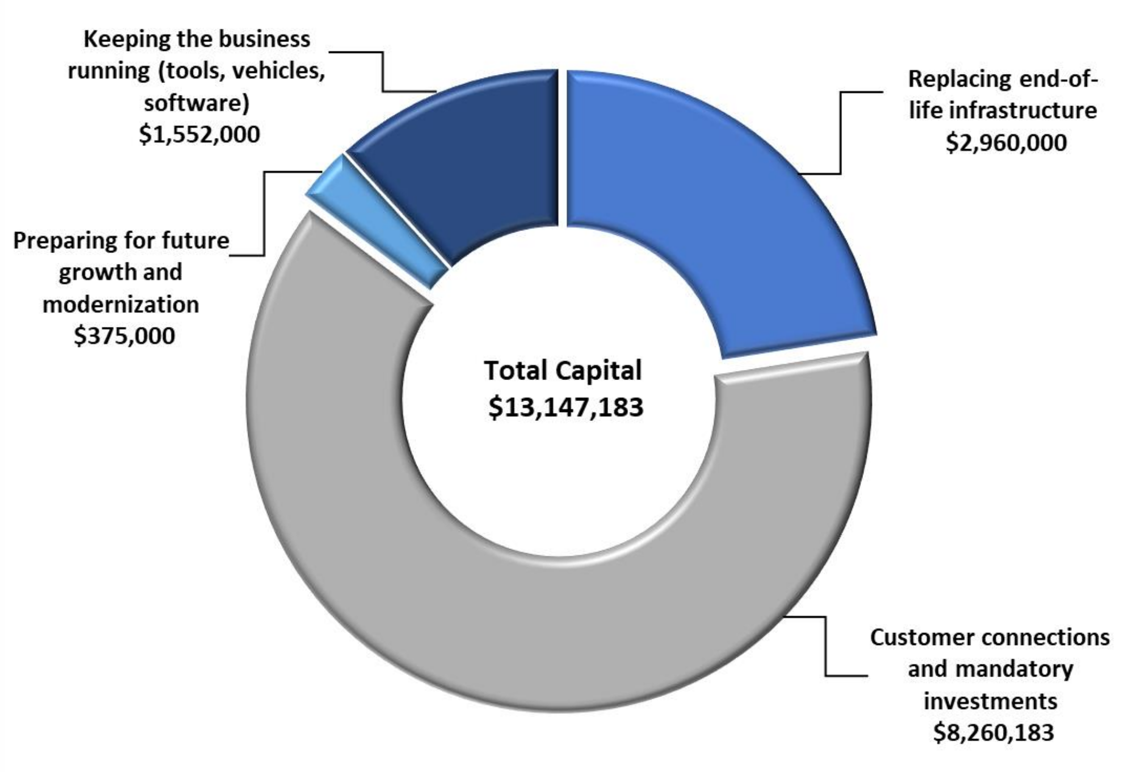
Over the course of the 2021-2025 period, BHI's investment needs are driven by deteriorating infrastructure, ongoing demand for new connections to the grid, changing electricity demand in pockets of the city, and technology changes.

BHI's capital and operating plans are focused on the following activities and customer outcomes:

- Renewing deteriorating infrastructure to maintain the reliability and safety of the system;
- Investing in grid resiliency and BHI's ability to respond to more frequent occurrences of adverse weather events;
- Ensuring sufficient short-term and long-term system capacity is available to meet customer demand;
- Meeting the utility's obligation to accommodate customer connections (e.g. new subdivisions, condo developments) and comply with other mandated service requirements (e.g. relocating poles due to road widening);
- Making prudent investments into non-distribution system assets (e.g. tools, vehicles, software) to enhance service offerings and support resource planning; and
- Maintaining a focus on continuous improvement, efficiency, and productivity.

HOW MUCH WILL BHI'S PLAN COST?

BHI's proposed capital investments in 2021 are $13,147,183. Proposed operating expenditures in 2021 are $21,497,775.



BHI Bill Breakdown

Electricity distributors like BHI are funded through the distribution rates paid by customers. BHI does not receive taxpayer money to fund its operations or investments in the distribution system. While BHI is responsible for collecting payment for the entire electricity bill, it retains only a portion of the delivery charge representing approximately 25% of the bill (see page 4).

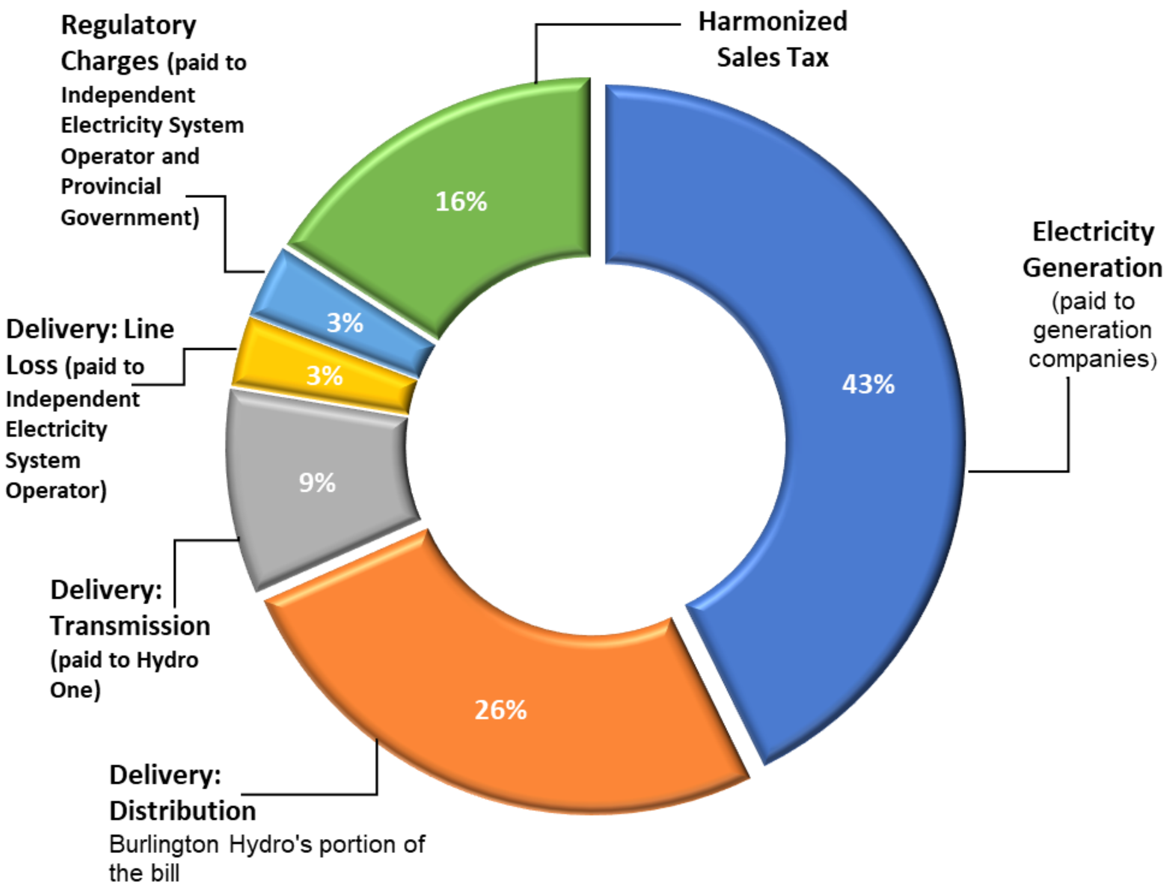
The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

Customer (Rate Class)	kWh Usage per Month	Total Bill Impact	
		$	%
Residential	750	$2.46	2.1%
General Service<50 kW	2,000	$6.34	2.2%

The Ontario Energy Board and intervenors representing various customer groups such as low-income consumers, school boards and commercial and industrial customers will review BHI's plan in a rigorous, transparent public hearing process.

BILL BREAKDOWN

These are the electricity charges for the average residential customer using 750 kWh per month. These percentages include the Ontario Electricity Rebate.



How to Stay Involved

For more information or to access BHI's complete application visit: https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

For more information on how to participate visit https://www.oeb.ca/participate.

From: Liz Russell <[redacted]>
Sent: Thursday, November 26, 2020 9:58 AM
To: registrar <registrar@oeb.ca>
Subject: EB-2020-0007 Complaint

We are in the midst of a pandemic and Burlington Hydro wants another increase ???

This is not inline with everyone who is struggling under orders to stay home, who have lost their jobs etc.

Entirely insensitive to behave as if life goes on.......for many people, life isn't going on, how does this application account for the outrageous approach when it does not reflect or take into account people's actual current circumstances.

Yours truly,

An Annoyed Burlington Resident

Liz

Burlington**hydro** inc.

Attention: Liz Russell
VIA EMAIL

December 2, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Ms. Russell,

Thank you for your Letter of Comment submitted to the Ontario Energy Board with respect to the residential rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You expressed in your letter that Burlington Hydro should not be proposing another increase in the midst of a pandemic. The proposed distribution rate increase in May 2021 is the result of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations. Distribution rates account for approximately 26% of the entire electricity bill.

Burlington Hydro submits this type of application - a Cost of Service application - to the Ontario Energy Board once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in residential rates beyond inflation is required next year to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g. poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan. Attached is a brief summary of our Application to provide you with some more information.

The Ontario Energy Board will only approve an increase to distribution rates if Burlington Hydro can provide adequate evidence to support the capital and operating costs that are contributing to the increase. Various intervenor groups, made up of experts who act on behalf of customers, will also review the application and may challenge the proposed rate changes.

There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program (CEAP), the Ontario Electricity Support Program (OESP), the Low-Income Energy Assistance Program (LEAP) and the Affordability Fund Trust (AFT). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

In addition, eligible customers are now able to choose between Time-of Use and Tiered electricity rates, which make up 43% of the average residential electricity bill. These rates are set by the Ontario Energy Board (OEB) bi-annually. Depending on how and when you use

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Burlington**hydro** inc.

electricity, changing your electricity price plan may save you money on your electricity bill. More information is available on our website at:
https://www.burlingtonhydro.com/billing/time-of-use-customer-choice-landing.html

Thank you again for your comments and please contact us with any further questions or concerns.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

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BURLINGTON HYDRO'S 2021- 2025 RATE APPLICATION

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- Ensuring sufficient short-term and long-term system capacity is available to meet customer demand;
- Meeting the utility's obligation to accommodate customer connections (e.g. new subdivisions, condo developments) and comply with other mandated service requirements (e.g. relocating poles due to road widening);
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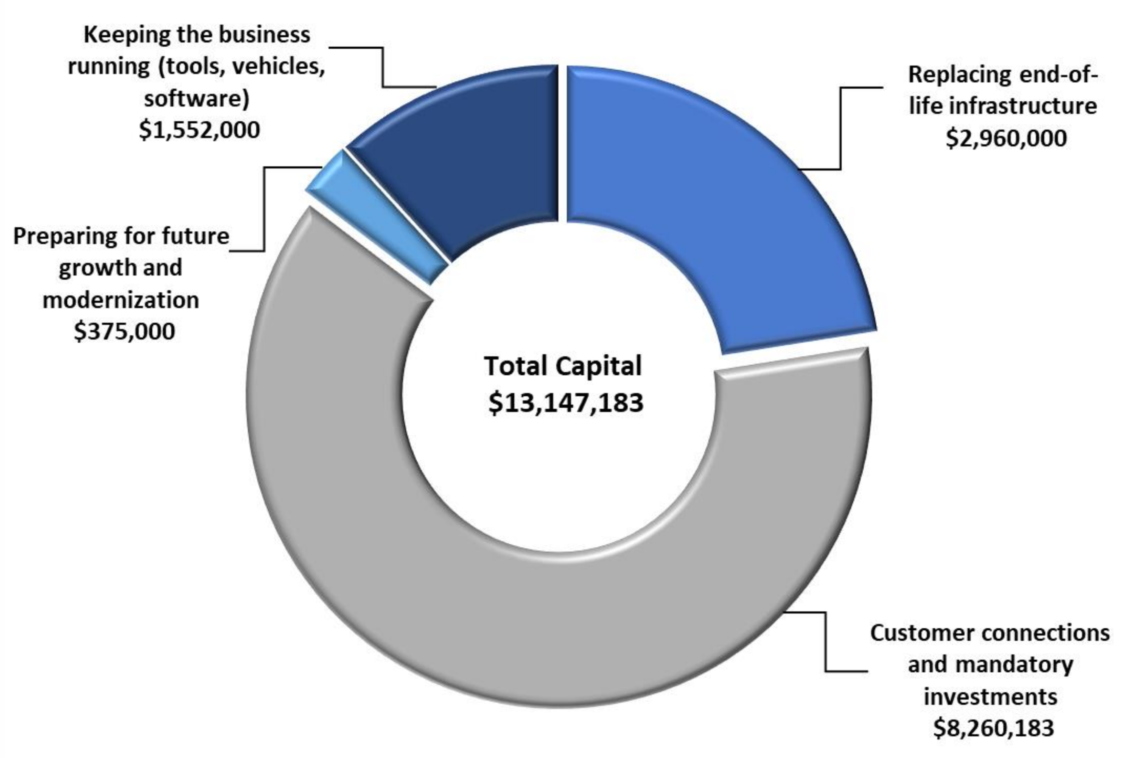


BHI Bill Breakdown

Electricity distributors like BHI are funded through the distribution rates paid by customers. BHI does not receive taxpayer money to fund its operations or investments in the distribution system. While BHI is responsible for collecting payment for the entire electricity bill, it retains only a portion of the delivery charge representing approximately 25% of the bill (see page 4).

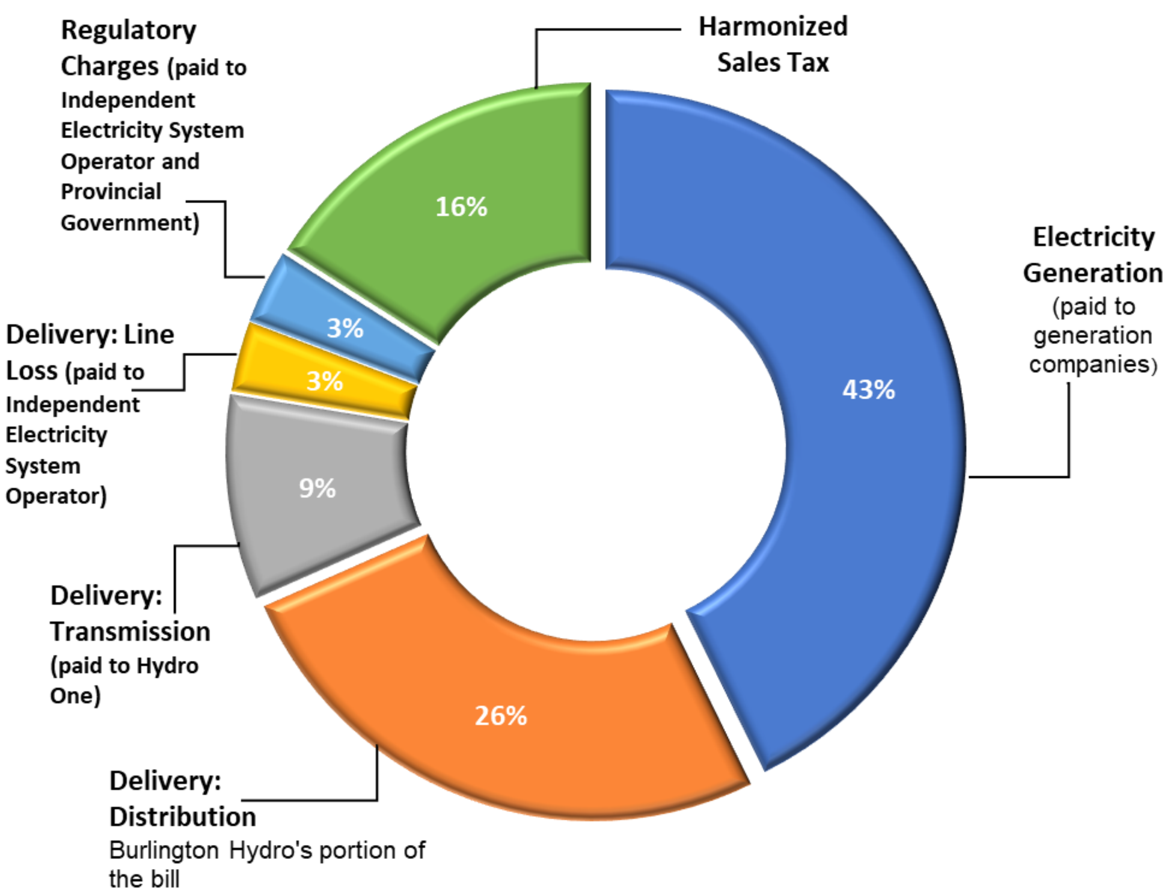
The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

Customer (Rate Class)	kWh Usage per Month	Total Bill Impact	
		$	%
Residential	750	$2.46	2.1%
General Service<50 kW	2,000	$6.34	2.2%

The Ontario Energy Board and intervenors representing various customer groups such as low-income consumers, school boards and commercial and industrial customers will review BHI's plan in a rigorous, transparent public hearing process.

BILL BREAKDOWN

These are the electricity charges for the average residential customer using 750 kWh per month. These percentages include the Ontario Electricity Rebate.



How to Stay Involved

For more information or to access BHI's complete application visit: https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

For more information on how to participate visit https://www.oeb.ca/participate.

From: registrar
To: Shelly-Anne Connell
Subject: FW: Letter of Comment - EB-2020-0007
Date: Tuesday, December 1, 2020 3:04:54 PM

-----Original Message-----
From: Webmaster <Webmaster@oeb.ca>
Sent: Sunday, November 29, 2020 10:31 PM
To: registrar <registrar@oeb.ca>
Subject: Letter of Comment - [redacted]

The Ontario Energy Board

-- Comment date --
2020-11-29

-- Case Number --
EB-2020-0007

-- Name --
Rafiq Dhanji

-- Phone --
[redacted]

-- Company --

-- Address --
[redacted]

-- Comments --
The materials that are presented do not make it easy for a consumer to understand what is being proposed, so my apologies if this is answered somewhere in the dozens of attachments. What is BHI doing to reduce their carbon emissions? What investment is there in renewable energies? Are there any planned incentives for customers to invest in renewables themselves to support the grid? What is BHI doing to create microgrids?

-- Attachment --

Burlingtonhydro inc.

Attention: Rafiq Dhanji

December 21, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Mr. Dhanji,

Thank you for your Letter of Comment submitted to the Ontario Energy Board ("OEB") with respect to Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and appreciate your interest in our Application with respect to the reduction of carbon emissions and renewable energies.

We appreciate that the Application is quite large, and information can be difficult to find. Burlington Hydro is involved in several initiatives that address some of your questions.

- We are partnering (through GridSmartCity) with McMaster University's Institute of Energy Studies who are leading the Integrated Community Energy and Harvesting System (ICE) research project. More information can be found here: https://www.gridsmartcity.com/partners-in-motion/innovation/mcmaster-ice/
- Burlington Hydro is 100% owned by the City of Burlington and we participate in infrastructure planning on a regional basis to ensure regional issues and requirements are effectively integrated into our planning processes. The Halton Region Official Plan, which includes Healthy Communities Policies is available here: Halton Region Official Plan;
- Electricity consumers in Ontario who produce some of their own power from a renewable resource may take advantage of the "net metering" initiative. Net metering allows consumers to send excess electricity that they generate from renewable resources to the distribution system for a credit toward their energy costs;
- We ensure we have adequate capacity to connect renewable generation to our distribution system;
- The Independent Electricity System Operators ("IESO") established the Feed-in Tariff ("FIT") program to support the development of renewable electricity generation projects. These projects were supported by Burlington Hydro. The FIT program was cancelled by the Ministry of Energy, Northern Development and Mines ('MENDM") in 2016; however, any projects implemented prior to that date are still permitted to operate; and
- The Ministry of Energy, Northern Development and Mines is currently consulting with stakeholders, including local distribution companies such as Burlington Hydro on Community-Based Energy Systems that focus on Community Net Metering demonstration projects.

I have attached our 2019 community report which includes some information on the City of Burlington's Climate Action Plan, Electric Vehicle Charging Stations and our partnership (through GridSmartCity) with McMaster University as mentioned above.

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Burlington**hydro** inc.

The OEB and various intervenor groups, made up of experts who act on behalf of customers, will also review our Application and may have similar questions to those you posed in your letter. These questions and our responses will be filed with the OEB in early February here:

Burlington Hydro Rate Application EB-2020-0007

Thank you again for your comments and please contact us with any further questions or concerns.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

2019 community report

Burlington enterprises corporation

Our Commitment to Community

At Burlington Enterprises Corporation (BEC), we are committed to doing our part in keeping Burlington a great place to live, work and do business.

We understand the value of corporate responsibility and the need for environmental stewardship. We also understand the importance of providing safe and reliable electricity services that meet the needs of our customers, while supporting local economic growth.

Burlington Hydro takes great pride in contributing to its community by helping the City develop and implement its 'Climate Action Plan', supporting local business development activities, and delivering meaningful safety programs in our schools.

We're a progressive company committed to continuous improvement, system renewal and performance excellence. As such, by innovating and adopting new technologies into our business operations we are creating a financially viable and sustainable path forward.

> "We strive for excellence and continuous improvement in all aspects of our business."

Burlington Enterprises Corporation (BEC) – formerly Burlington Hydro Electric Inc. – is an energy services company that is wholly owned by the City of Burlington. BEC oversees two affiliate subsidiaries: a regulated "wires" company, Burlington Hydro Inc. (BHI) and an unregulated company, Burlington Electricity Services Inc. (BESI).

With a total licensed service area of 188 square kms, Burlington Hydro serves approximately 68,000 residential and commercial customers in the City of Burlington, delivering electricity into the community through a network of 1,600 kms of medium-voltage distribution lines and 32 substations.

Delivering Value Back to Our Community

Message from the Chair and CEO

John Maheu, Chair

Pre-Pandemic

Striving for excellence across all aspects of our business reflects a commitment that lies at the very core of our company – caring for people and community, and caring about stewardship and sustainability. We are deeply influenced by local priorities and what that means when it comes to delivering value to our customers and the community. We're pleased to report that Burlington Enterprises Corporation's (BEC) performance in 2019 mirrored these foundational principles, while achieving strong financial results for our shareholder.

Foremost, we remain focused on delivering long-term value by operating an efficient, profitable and community-minded utility, committed to doing its part in ensuring a prosperous future for our City. Our goal is to contribute in a positive way to the City's strategic objectives, particularly as it relates to economic growth and environmental leadership, including any contributions we can make in the implementation of the City of Burlington's Climate Change Action Plan.

We are very proud of achieving a 96 percent satisfaction rating from customers in our 2019 annual survey. In a rapidly evolving industry environment where innovation and increasing customer expectations often carry the day, we are ensuring that we stay one step ahead of the industry curve.

By initiating a number of improvement projects in 2019, our customers continued to reap the benefits of greater efficiencies and improved customer care. Our commitment to continual re-evaluation and improving services remained central to our approach. A number of these initiatives are described in the report that follows.

From building cyber security resiliency to upgrades to our Geographic Information System (GIS), we're also ensuring our systems are current, robust, and most importantly, secure. We spent considerable time and effort on initiating the integration of a new Customer Information System (CIS). The new CIS will provide the flexibility to meet future industry needs and changing customer requirements. It is slated for implementation in 2020.

Staying ahead of our regulatory commitments can be an ongoing challenge in of itself. In 2019, we began to develop our Cost of Service (COS) rate application for 2021 to 2025. This lengthy process takes close to two years of coordination as thousands of pages of evidence are brought together for submission to the Ontario Energy Board (OEB). The application is due in October 2020, and will be effective beginning May 1, 2021. The ability to recover prudently incurred costs and earn the approved rate of return is dependent on a successful COS application.

We must always stay mindful of changes to public policy that could impact our business. In the spring of 2019 the Ontario government passed legislation that centralized the delivery of conservation programs to the Independent Electricity System Operator (IESO). For the first time in over a decade, we were no longer responsible for delivering conservation programs to our customers as we had for over a decade.

As we have discovered in the past, it's been our ability to adapt and evolve in an ever-changing industry environment that has kept us successful.

Our corporation's consistent and strong financial performance has ensured once again the delivery of reliable dividends and interest payments to our shareholder in 2019. We're pleased to report that we continued to meet our goals and financial targets. The company has made a dividend payment to the City now for 19 consecutive years, representing over $115 million. We are very proud of our strong financial performance.

Looking Forward, a New Reality

In advance of the publication of this report, a major global and societal upheaval has occurred. The COVID-19 pandemic has severely impacted the economy and changed everyday life in a very powerful way as entire countries self-isolate and businesses are shut down. The Ontario Government has designated Burlington Hydro as an essential workplace and as such we're continuing to operate, albeit in a very different manner. Physical distancing, working in rotation between home and office, and ensuring the health and safety of our employees has become the new norm.

Gerry Smallegange, CEO

We are committed to ensuring that the lights stay on – that the hospital, essential services and the many people who are self-isolating at home can depend on a safe and reliable distribution system as we work through these challenging times.

As many businesses and individuals are financially affected, so will our business feel the financial impact of the pandemic. With fewer commercial businesses operating, electricity demand is down 10% in Ontario. A number of our customers will feel the hardship of paying their bills as the economy continues to be shut down. We will re-evaluate our financial forecasts in the months ahead, but much remains unknown as we move forward to the end of the year.

There remain actions that we can take, that support our community and provide a sense that we are in this together. We're very proud to have been a part of helping in the construction of Joseph Brant Hospital's 93-bed Pandemic Response Unit on the property of the hospital. Burlington Hydro donated the electrical services and equipment and then in record time, ensured those services were safely installed and ready for use to support patient care.

More than ever, seeing the positive in challenging times keeps us resilient. It is the kind of resilience that we as a company will continue to demonstrate as we look to the future.

Our Community Reach

E-Billing Campaign Supports Joseph Brant Museum Transformation Project

Burlington Hydro launched a campaign in 2019 to promote paperless billing and enrolment in the utility's e-billing service, VIEWmybill. Under the program, with every new customer registration a $5 donation was made by Burlington Hydro to the Burlington Museums Foundation to support the Joseph Brant Museum Transformation project. "We're thrilled to run a campaign that will encourage more customers to sign up for our paperless e-billing service while supporting the transformation of such an important cultural landmark in our City," said Gerry Smallegange, President and CEO, Burlington Hydro Inc.

> "Not only do we believe strongly in supporting the cultural enrichment of our community, but we applaud the sustainable and energy efficient aspirations to attain a Platinum LEED designation for the new building."

Burlington's 'Climate Action Plan'

In April 2019, Burlington City Council declared a climate emergency in response to concerns about the impact of a changing climate.

The drafting of a Climate Action Plan (CAP) was initiated by the City to provide the framework for reducing the use of fossil fuels and greenhouse gas emissions. As a CAP Stakeholder Committee member, Burlington Hydro is providing its expertise to help contribute to the development of the plan that focuses on deep energy building retrofits, renewable energy and electric mobility, among other program areas. The draft CAP is being brought before Council in 2020 for final approval.

Burlington Hydro places a high priority on building a strong relationship and strategic alignment with the City. This includes our ongoing support of the City's Strategic Plan – From Vision to Focus – and the contributions we can make to help the City attain its goals, particularly in the area of economic development. Bringing tangible benefit to our community continues to be our focus.

Engaging in Our Community

Burlington Hydro believes strongly in giving back to the community.

We proudly support a number of local programs, cultural organizations and charities in the City of Burlington:

Burlington Green
Carpenter Hospice
Halton Women's Place
Terry Fox Run Burlington
Halton Crime Stoppers
Burlington Chamber of Commerce
Burlington Museums Foundation
Art Gallery of Burlington
Joseph Brant Day Festival
Appleby Street Festival
Lowville Festival

United Way of Burlington

From silent auctions to employee barbecues, fundraising events were held throughout the year to support the annual United Way campaign. Employees also give through a payroll deduction program, whereby the company matches all donations. Close to $15,000 was raised for the United Way Campaign in 2019.

Burlington's Lakeside Festival of Lights

2019 marked the 24th annual Burlington Festival of Lights, a holiday tradition at Spencer Smith Park on the City's waterfront. Tens of thousands of families, local residents and tourists take in the 40-day seasonal festival coordinated by Burlington Electricity Services. The festival is made possible with the generous support of community businesses and organizations, and a dedicated team of volunteers. Our team of local high school students constructed the festival's newest display for 2019: 'Happy New Year'.

286,700 people saw the event on their Facebook news feed

10,700 people responded as interested in going or going to the event

New Phone System Enhancements

All calls are important to us. That's why Burlington Hydro has enhanced its phone service with a new call-back feature that kicks in if customers are unable to get through to a customer service representative. It means customers needn't stay on the line while on hold, they simply request a call back. Each customer's priority is then maintained in a queue and they are called back as soon as an agent becomes available.

Improving the Customer Experience

Burlington Hydro is continually re-evaluating its services to ensure that customer expectations are being met. That's why the company conducts a yearly Customer Satisfaction Survey, through its partner UtilityPULSE. Not only does the survey provide a window into what is working, but it helps to support discussions around improving customer care at every level of the company.

A Re-designed, More Intuitive Website

In 2019, the Burlington Hydro website – BurlingtonHydro.com – was completely re-designed to offer customers a more intuitive and enhanced web experience. Among other new functions, the homepage features a sliding scale that provides to-the-minute time-of-use prices and times. There's greater use of pictorial images that link to relevant sections and portals such as the Tools and Resources webpage, while enabling a more intuitive navigation of the site. The website improvements also provide for an enhanced experience for mobile and tablet users.

Power Reliability that Delivers

330 utility poles installed in 2019	**241** new service connections in 2019	**38** overhead transformer banks installed in 2019	**68** padmount and submersible transformers installed in 2019

93% of customers agree that Burlington Hydro provides consistent reliable power

93% of customers agree that the standard of reliability meets expectations

89% of customers agree that Burlington Hydro quickly handles outages

Tremaine TS Egress Feeders

Tremaine transformer station (TS) first delivered power to Burlington Hydro in 2014. Since that time, Burlington Hydro has continued to extend egress feeders further into the city to better balance the power supplied by the different transformer station locations. In 2019, a main feeder egress project was constructed along Walkers Line to the Palmer Distribution Substation, south of Upper Middle Road.

Connecting feeders are not only allowing power loads to be more evenly shared between the five transformer stations that serve the City, but are also allowing for more flexible operation by Control Room Operators during power outages.

Substation Transformer Replacement

A large part of Burlington Hydro's distribution system was put into service decades go, and although it has been regularly maintained and upgraded over the years, the basic configuration employed at numerous distribution substations remains. 32 distribution substations operate in Burlington – they essentially reduce voltage to the operating level of the distribution feeders in different parts of the city.

The transformers within these substations have a typical service life of 40 years and are regularly tested to ensure they are functioning properly. Each year, Burlington Hydro replaces one or two substation transformers. In 2019, transformers first installed in 1971 and 1983 were replaced at Hampton DS.

Burlington Hydro is now using dry-type transformers in place of the older oil-filled units. Because dry-type transformers use air as the cooling medium, they have proven to be more environmental, while posing less fire and safety hazards as their oil counterparts.

Innovations that Move Us Forward

Geographic Information System (GIS) Upgrades

Burlington Hydro's Geographic Information System (GIS) is a scaled, electrically connected model of the City's distribution system. In 2019, technical support for Burlington Hydro's GIS software, which had been used for over a decade, was discontinued. After evaluating a number of alternatives, the Hexagon GIS platform was selected. The new platform demonstrates greater functionality, data enhancement, reporting and process efficiencies. It was successfully implemented in late 2019 and went live in 2020.

Comprehensive Cyber Security Protection

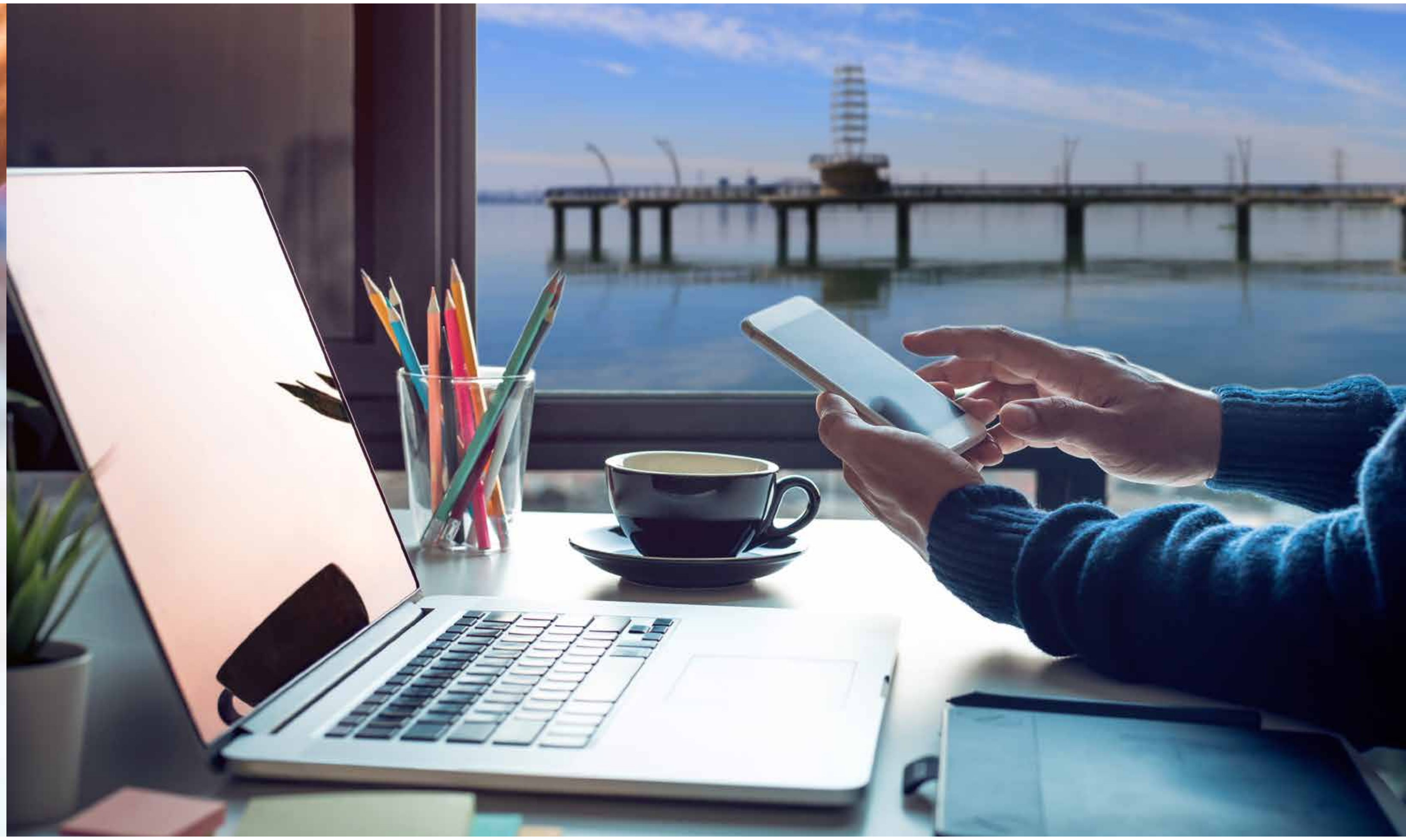
Burlington Hydro maintains a vigilant focus on cyber risk in order to ensure the integrity of its operations, processes and business systems. The company continues to evolve their Information Security Management Program in alignment with the Ontario Cyber Security Framework for electricity utilities and in response to the ever changing Cyber Security threat landscape. The ongoing integration of the framework in 2019 continued to build cyber resiliency within Burlington Hydro, ensuring comprehensive security protection of the company's digital assets.

Electric Vehicle Charging Stations for Condominiums

In recent years, Burlington Electricity Services Inc. (BESI) has offered managed Electric Vehicle (EV) charging solutions to both single detached home owners and multi-unit residential condominium owners. In 2019, BESI's primary focus was to grow its program with the installation of Level 2 charging stations in condominium parking garages.

Ongoing discussions with condo developers have resulted in an approach that meets the needs of prospective suite owners who plan to own EVs, without impacting those who do not. The program also allows buildings that were not designed to carry Electric Vehicle loads to allow EV charging by the condo's suite owners. The system manages energy flows that respond to the needs of the unit owners and the capacity limits of the building's electrical service. BESI is at various stages of implementation with Paradigm, Bridgewater, Bunton's Wharf and the Baxter buildings in Burlington.

Cooperative Action



Cooperative Thinking, Collaborative Action

As a GridSmartCity Cooperative (GSCC) partner, Burlington Hydro is pursuing efficiencies and service improvements by pooling best practices and resources with like-minded utility partners. The GSCC continues to foster relationships that encourage synergies with a shared desire to work together to build strong, sustainable communities.

The Cooperative provides Burlington Hydro with opportunities to collaborate and share knowledge, skills and expertise, while realizing cost savings. Whether it's single phase transformer pole mounts, or pole line insulators and brackets, collective purchasing is realizing savings for partner LDCs.

There are also a number of important projects/initiatives taking place, including among others:

- A 'Feeder of the Future' project with corporate partner S&C in collaboration with Burlington Hydro and Energy+ to provide scenarios and model parameters;
- A proposal from GSCC, AESI and Mohawk College to access provincial government funding under the Ontario Research Excellence Fund to further explore Operational Technology Cyber Security audits; and,
- GSCC's ongoing partnership with McMaster University's Institute of Energy Studies who are leading the Integrated Community Energy and Harvesting System (ICE) research project.

Fifteen member utilities make up the GridSmartCity Cooperative: Burlington Hydro, Brantford Power, Energy+, ERTH Power, Entegrus, Essex Power Lines, EnWin Utilities, Halton Hills Hydro, Kingston Hydro, Kitchener Wilmot Hydro, Milton Hydro, Niagara Peninsula Energy, Oakville Hydro, Waterloo North Hydro, and Welland Hydro Electric System.

Developing the Cost of Service Application

Every five years, the Ontario Energy Board (OEB) requires LDCs to file a Cost of Service application. This extensive review of the cost to serve customers includes thousands of pages of evidence, responses to hundreds of questions from the OEB and intervenor groups, as well as extensive expert witness testimony from applicants. In early 2019, Burlington Hydro began the process of developing its 2021-2025 Cost of Service rate application.

Customer engagement has been an important part of developing the application. Beginning in the spring of 2019, Burlington Hydro began to gather feedback from its residential, small business and commercial customers on its draft Business Plan, which underpins the application. A series of focus groups, and telephone and online surveys were conducted in 2019 and will continue into 2020.

Another major component of the rate application is the capital investment plan. In order to optimize investment decisions and prioritize Burlington Hydro's investment portfolio, new tools were introduced to the Asset Management process. The company conducted an Asset Condition Assessment providing planners with critical data to help make investment decisions going forward. These improvements lay the groundwork for a robust Asset Management strategy that leverages data-driven decision support tools, critical to the success of the Cost of Service application.

The application will be submitted in 2020. The OEB's decision will determine distribution rates that will be effective May 1, 2021.

Fast Facts

Viewing the Outage Map webpage
PAGE VISITS
250,184

Contacting us by telephone
43324 CALLS ANSWERED
CALLS ANSWERED WITHIN 30 SECONDS 82%
SERVICE LEVEL 82% (17% above OEB standard)
1,862 WATER RELATED CALLS
SERVICE REQUESTS 13,223

What Our Customers are Saying
96% OVERALL CUSTOMER SATISFACTION SCORE
91% OF CUSTOMERS AGREE THAT WE ARE A TRUSTED AND TRUSTWORTHY COMPANY
91% OF CUSTOMERS AGREE THAT WE PROVIDE EXCELLENT QUALITY SERVICES

Why are customers calling?

START STOP SERVICE	24%
BALANCE INQUIRY	10%
CREDIT INQUIRY	7%
BILLING INQUIRY	18%
WATER INQUIRY	5%
VIEWMYBILL/ TOU TOOLKIT	2%
OTHER INQUIRY	34%

Engaging online burlingtonhydro.com
VISITORS 589,045
384,676 BY DESKTOP
BY MOBILE 399,166
BY TABLET 53,298

ViewMyBill Paperless Billing
24,720
CUSTOMERS SUBSCRIBED

Time-of-Use (TOU) Toolkit
(The toolkit is a web based tool that helps customers manage electricity costs/usage)
12,282
CUSTOMER SUBSCRIBERS

Connecting to Twitter
209 TWEETS
TWEET IMPRESSIONS
1,217,900
PROFILE VISITS
124,722
(up 15% from 2018)

2019 CANADA'S SAFEST EMPLOYERS
SILVER WINNER

Safety is Our #1 Priority

Improving Safety and Reducing Risk for Our Employees

After achieving the highest level of Zero Quest, formerly the Electrical and Utility Safety Association's Health and Safety Management program, Burlington Hydro has embarked on the newest safety management program from the Workplace Safety and Insurance Board (WSIB). The Health and Safety Excellence Program is administered and managed for the utility sector through the Infrastructure Health and Safety Association (IHSA).

Burlington Hydro's focus is to continue to reduce risk factors while implementing continuous improvement opportunities in a leading indicator program. The program will further expand our health and safety culture, finding new and creative ways to improve safety and reduce risk within Burlington Hydro and the community. The goal is to become an accredited organization recognized by the Ministry of Labour and Workplace Safety and Insurance Board.

> “There is no job, no emergency, and no situation that cannot be done safely. We practice safety prevention to reduce risk in all areas of our business and community.” Andy Kerr, Director, Health and Safety, Security and Environment

Award Winning

For the second year running, Burlington Hydro received national recognition from Canadian Occupational Safety for achieving industry excellence in employee health and safety. The company was awarded Silver in the Utilities and Electrical category as Canada's Safest Employer 2019. The award recognizes companies from across Canada with outstanding accomplishments in promoting the health and safety of their workers. Utilities are judged on a wide range of occupational health and safety elements, including employee training, Occupational Health and Safety management systems, incident investigation, emergency preparedness and innovative health and safety initiatives.

Burlington Hydro - Productive hours since last 'Lost Time Incident':

878,691

Creating Safety Awareness in our Community

To gauge the level of public safety awareness, Burlington Hydro undertakes a bi-annual public survey. The Electrical Safety Awareness Survey was last conducted in 2018, achieving an 84% public awareness index score – a score 4 percentage points higher than our previous survey. The survey is scheduled to be taken again in 2020.

Customers and the general public can find extensive information on powerline and electrical safety on Burlington Hydro's web portal: Power to Be Safe. Among other features, the portal houses an animated video series to help educate the community about electricity dangers. Safety messaging is also an important part of our social media feed and is often featured content on Twitter @BurlingtonHydro.

We recognize that creating powerline and electrical safety awareness in our community begins with the education of our children. The Burlington Hydro 'Power to Be Safe' Roadshow is an interactive, content-packed presentation, designed especially for young students. School safety sessions were held in twelve Burlington Public and Elementary Catholic schools in 2019. That represents over 4,600 school children from Kindergarten to Grade 8 who received instruction on powerline and electrical safety. The school program continues to be Burlington Hydro's most popular and enduring initiative.

A Company Culture Committed to Excellence

“Burlington Hydro’s culture focuses on the promotion of employee wellbeing, diversity and growth.”

Jennifer Smith, VP Corporate Relations and Chief Human Resources Officer

An Award-Winning Top Employer

Burlington Hydro was recognized as a Hamilton-Niagara Top Employer in 2019 by the editors of Canada’s Top 100 Employers. The regional designation recognizes Hamilton-Niagara area employers who are industry leaders in offering exceptional places to work.

Burlington Hydro was evaluated using the same criteria as that used in the national competition: Physical Workplace; Work Atmosphere & Social; Health, Financial & Family Benefits; Vacation and Time Off; Employee Communications; Performance Management; Training & Skills Development; and Community Involvement. Burlington Hydro was compared to other organizations to determine which offers the most progressive and forward-thinking programs.

Apprenticeships

Anticipating the need for qualified trades’ personnel over the next five to ten years, Burlington Hydro continues to hire apprentices to ensure that skilled workers are there to maintain a sustainable, safe, and reliable distribution system into the future. It takes four years of apprenticeship or formal training, and several more years of hands-on experience to hone the skills that are necessary to perform work on an electrical distribution system. In 2019, Burlington Hydro welcomed two new apprentices into its work family, bringing the total to nine apprentices who are in various stages of skill development.

Training the Workforce of the Future

Burlington Hydro introduced a robust, new training regime in 2019 for online employee training. Employees can take advantage of a wide variety of convenient, timely and topical course offerings to further enhance their professional development. Course offerings come under three broad categories: General; Leadership; and, Workplace Safety and Wellness. From conflict resolution and diversity in the workplace, to protecting confidential information and office ergonomics, the course selection offers a wide array of choice for both young and seasoned employees with over 50 instructional modules.

Learning is complemented by other training programs including: a partnership with Benchmark Learning Systems, IHSA and utility partners to offer progressive powerline training videos; and, Mohawk College Enterprise’s ‘Future Ready Leadership Essentials’ program that consists of five leadership training courses delivered over four months and customized specifically to accommodate the needs of GridSmartCity LDC partners.

A New and Integrated HR Information Solution

In 2019, Burlington Hydro implemented a comprehensive software platform to digitize its payroll and Human Resources functions. The integrated, self-serve system has eliminated manual administrative procedures and made it easier to process payroll in a timely and accurate fashion. The Dayforce Enterprise system has a number of convenient and secure self-serve features that includes, among others: digital timesheets, pay statements, and easy access to personal data.

The Dayforce system also provides new ways to deliver human resources information and processes to employees. From facilitating the new employee onboarding experience to accessing training material and housing company policies and procedures, the platform brings a number of functions under one umbrella. These additional features will be introduced through 2020 and 2021.

The integration of Dayforce is modernizing our approach to communicating with employees, while reducing our environmental footprint with the reduction/elimination of paper records.

2019 Hamilton-Niagara’s Top Employers

Above board

In the fall of 2019, Burlington City Council approved the holding company name change from Burlington Hydro Electric Inc. (BHEI) to Burlington Enterprises Corporation (BEC). BEC's governance structure is in line with industry best practices and provides greater flexibility for business growth into the future.

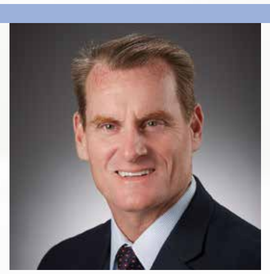
board of directors

John Maheu
Chair

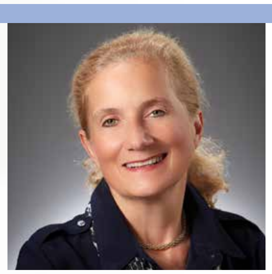
Mayor
Marianne Meed Ward

Susan Kilburn

Sherry Smith

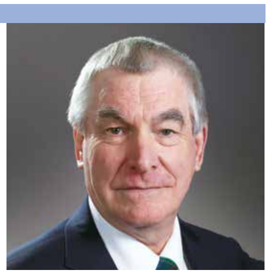


David Kerr



Patricia Volker

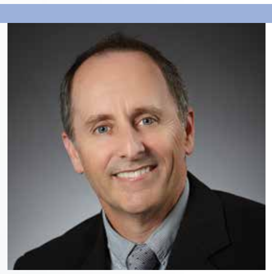
Tim Commisso



Archie Bennett

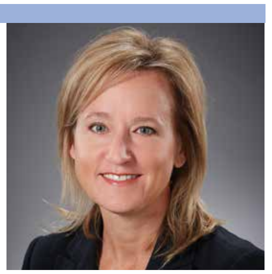
leadership team

Gerry Smallegange
President and Chief Executive Officer



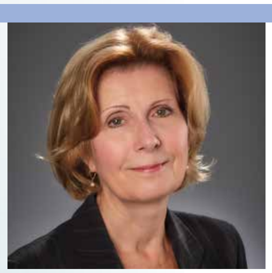
Michael Kysley
Executive Vice President and Chief Financial Officer

Dan Guatto
Vice President, Engineering and Operations, and Chief Operating Officer

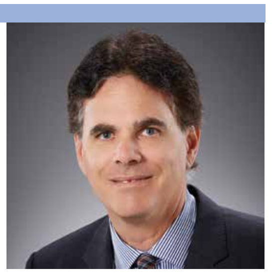


Jennifer Smith
Vice President, Corporate Relations and Chief Human Resources Officer

Sally Blackwell
Vice President, Regulatory Compliance and Asset Management



Marianne Blasman
Vice President, Information Technology and Chief Information Officer



Joe Saunders
President, Burlington Electricity Services Inc.

Shareholder Report

2019 Burlington Enterprises Corporation (BEC) Consolidated Financial Performance at a Glance

Looking back at 2019, the strong and consistent financial results are the result of an entire organization successfully executing our operational and financial strategy. We have a commitment to provide the best possible value proposition to our customers, shareholder and stakeholders.

Our strong balance sheet provides the foundation to continue to invest in the assets needed to provide a safe, reliable and secure electricity distribution network in the City of Burlington.

Our customer centric emphasis combined with a strong risk culture, focuses our capital spending on projects that enhance reliability of the electricity grid. Enabling technologies that create efficiencies, enhance cyber security and improve customer interactions are at the core of our investments in new software platforms.

In 2019, Burlington Enterprises Corporation invested $14.5M in its capital expenditure program.

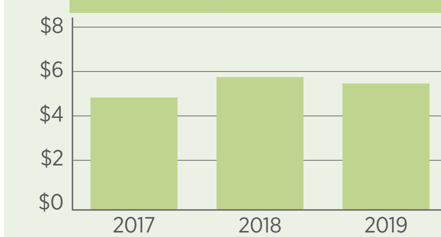
Financial Highlights For the year ended December 31 (Canadian $ in millions)	**2019**	**2018**
Financial Results		
Gross Revenue	228.5	225.5
Operating Expenses	21.1	23.1
Net Income	5.6	5.9
Balance Sheet Information		
Total Assets	216.2	206.7
LT Debt less current maturities	64.7	66.1
Total Shareholder's Equity	88.4	85.3
Financial Measures		
Return on Equity	6.4%	6.9%
Operating Expenses as a % of Gross Revenue	9.3%	10.2%
Value Measures		
Dividend Yield	5.7%	7.3%
5 Year Ave Dividend Payout Ratio	52%	50%

Diversified Sales

With approximately 61,500 residential, 5,500 small commercial and 1,000 large accounts, Burlington Hydro has a diversified customer base.

15%	24%	61 %
Small Commercial	Large Commercial & Industrial	Residential

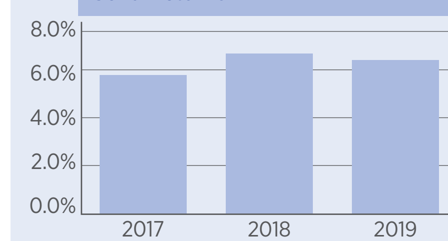
Net Income $5.6 million
Stable Earnings (millions)



With a proven record of delivering consistent financial performance, 2019 saw strong results for our company, with a Net Income of $5.6 million. Maintaining a focus on building a competitive cost structure has enabled the company to both reinvest for the future and meet its annual financial targets.

We continue to use a more flexible cost base using supplier partnerships and channels such as GridSmartCity. Working with other like-minded LDC's, GridSmartCity is an agent allowing for greater collaboration and cost sharing of services.

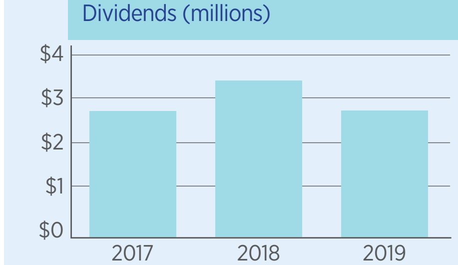
Return On Equity 6.4%
Solid Returns



Our ability to deliver on and respond to continuous regulatory changes with speed and reliability is reflective of our agile enterprise. The growing and more complex challenges in the regulatory environment today have led Burlington Hydro to continue to create new business approaches, partnerships and solutions.

The Corporation's main business, utility operations, is highly regulated and the earnings are primarily determined under cost of service ("COS") regulation. The ability to recover prudently incurred costs and earn the approved rate of return is dependent on a successful COS application, the next being 2021.

Dividends & Interest $4.9 mil
Dividends (millions)



Burlington Enterprises Corporation is committed to creating value for our shareholder by delivering sustainable earnings which generate a consistent dividend stream.

2019 marks 19 consecutive years that BEC has made a dividend payment to the City of Burlington with total interest and dividends since 2001 exceeding $115 million.

In 2019, the City of Burlington received $2.6 million in dividends from BEC and interest revenue from Burlington Hydro Inc. of $2.3 million for a total cash return of $4.9 million.

Taking a Long-Term View

Our goal is to continue to emphasize financial discipline and execution in order to maintain our competitive cost structure. Focusing on implementing productivity improvements and cost reduction strategies while strengthening service quality will serve both our customers and our shareholder in the future.

Our business model, underpinned by a rigorous capital investment review process has been the backbone of our value proposition. Through this model, Burlington Hydro is well positioned for the challenges and opportunities in the electricity sector.

The following summary financial statements are based upon the audited financial statements of Burlington Enterprises Corporation

Burlington Enterprises Corporation

Consolidated Statement of Financial Position

Year ended December 31, 2019, with comparative information for 2018

	2019	2018
Assets		
Current assets		
Cash	$ 5,656,048	$ 14,812,404
Securities held as customer deposits	3,898,230	3,835,064
Accounts receivable	16,718,017	18,356,712
Work in progress	704,966	625,027
Unbilled revenue	23,544,011	19,941,776
Income taxes receivable	248,940	296,100
Materials and supplies	5,349,648	4,623,187
Prepaid expenses	541,187	548,104
Total current assets	56,661,047	63,038,374
Non-current assets		
Right-of-use assets	417,076	437,557
Property, plant and equipment	141,523,542	130,183,885
Intangible assets	9,840,281	6,984,509
Deferred tax assets	7,737,217	6,078,843
	159,518,116	143,684,794
Total assets	216,179,163	206,723,168
Regulatory balances	24,651,404	21,503,996
Total assets and regulatory balances	$ 240,830,567	$ 228,227,164

Consolidated Statement of Financial Position Continued

	2019	2018
Liabilities and Shareholder's Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 18,187,362	$ 14,624,377
Current portion of lease liabilities	113,638	253,459
Current portion of long-term debt	1,327,400	1,273,824
Customer deposits	3,898,230	3,835,064
Work order deposits	4,536,058	4,985,112
Deferred revenue	1,516,586	1,716,709
Other liabilities	2,363,046	3,755,831
Total current liabilities	31,942,320	30,444,376
Non-current liabilities		
Deferred revenue	23,304,474	17,568,377
Deferred tax liabilities	10,914,281	8,138,608
Long-term lease liabilities	101,572	16,897
Long-term debt	64,747,451	66,074,286
Liability for future benefits	4,489,718	4,870,343
Total non-current liabilities	103,557,496	96,668,511
Total liabilities	135,499,816	127,112,887
Shareholder's equity		
Capital stock	45,639,338	45,639,338
Paid-up capital	876,228	876,228
Retained earnings	42,082,095	39,395,066
Accumulated other comprehensive loss	(181,690)	(546,624)
Total shareholder's equity	88,415,971	85,364,008
Total liabilities and shareholder's equity	223,915,787	212,476,895
Regulatory balances	16,914,780	15,750,269
Total liabilities, shareholder's equity and regulatory balances	$ 240,830,567	$ 228,227,164

Consolidated Statement of Comprehensive Income

Year ended December 31, 2019, with comparative information for 2018

	2019	2018
Revenue		
Distribution revenue	$ 31,140,120	$ 30,706,157
Other operating revenue	4,187,359	6,965,394
	35,327,479	37,671,551
Sale of electricity	193,222,328	187,840,861
Total revenue	228,549,807	225,512,4124
Operating expenses		
Operations and maintenance	9,726,670	12,154,452
Billing and customer service	2,923,216	3,312,296
General administration	8,502,941	7,636,987
Depreciation and amortization	6,444,970	6,021,749
	27,597,797	29,125,484
Cost of power purchased	193,448,741	189,166,371
Total expenses	221,046,538	218,291,855
Income from operating activities	7,503,269	7,220,557
Net finance costs	(2,873,077)	(2,735,963)
Income before income taxes	4,630,192	4,484,594
Income taxes		
Current	343,872	568,747
Future	985,733	1,424,045
	1,329,605	1,992,792
Net income after income taxes	3,300,587	2,491,802
Net movement in regulatory balances, net of tax		
Net movement in regulatory balances	646,151	2,345,628
Income tax on net movement in regulatory balances	1,336,746	779,583
	1,982,897	3,125,211
Net income and net movement in regulatory balances	5,283,484	5,617,013
Other comprehensive income		
Remeasurements of liability for future benefits, net of tax	364,934	249,569
Total comprehensive income	$ 5,648,418	$ 5,866,582

Consolidated Statement of Changes in Equity

Year ended December 31, 2019, with comparative information for 2018

	Share capital	Contributed surplus	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2018	$ 45,639,338	$ 876,228	$ 37,128,053	$ (796,193)	$ 82,847,426
Net income and net movement in regulatory balances	-	-	5,617,013	-	5,617,013
Other comprehensive income	-	-	-	249,569	249,569
Dividends	-	-	(3,350,000)	-	(3,350,000)
Balance at December 31, 2018	$ 45,639,338	$ 876,228	$ 39,395,066	$ (546,624)	$ 85,364,008
Balance at January 1, 2019	$ 45,639,338	$ 876,228	$ 39,395,066	$ (546,624)	$ 85,364,008
Transitional adjustment	-	-	3,545	-	3,545
Adjusted balance at January 1, 2019	45,639,338	876,228	39,398,611	(546,624)	85,367,553
Net income and net movement in regulatory balances	-	-	5,283,484	-	5,283,484
Other comprehensive income	-	-	-	364,934	364,934
Dividends	-	-	(2,600,000)	-	(2,600,000)
Balance at December 31, 2019	$ 45,639,338	$ 876,228	$ 42,082,095	$ (181,690)	$ 88,415,971

Consolidated Statement of Cash Flows

Year ended December 31, 2019, with comparative information for 2018

	2019	2018
Operating activities		
Net income and net movement in regulatory balances	$ 5,283,484	$ 5,617,013
Adjustments for:		
Depreciation and amortization	6,444,970	6,021,749
Amortization of deferred revenue	(477,936)	(375,497)
Post-employment benefits	115,875	53,101
Losses on disposal of property, plant and equipment	82,540	305,325
Net finance costs	2,873,077	2,735,963
Income tax expense	1,329,605	1,992,792
Contributions received from customers	6,214,033	3,151,664
Change in non-cash operating working capital:		
Accounts receivable	1,638,695	2,199,541
Work in progress	(79,939)	(364,475)
Unbilled revenue	(3,602,235)	(1,138,079)
Materials and supplies	(726,461)	(1,125,726)
Prepaid expenses	6,917	(82,298)
Accounts payable and accrued liabilities	3,562,985	(3,357,804)
Work order deposits	(449,054)	1,430,697
Deferred revenue	(200,123)	851,491
Other liabilities	(1,392,785)	(379,859)
	20,623,648	17,535,598

Consolidated Statement of Cash Flows Continued

	2019	2018
Regulatory balances	$ (1,982,897)	$ (3,125,211)
Income tax paid	(504,064)	(918,977)
Income tax received	207,352	1,300,129
Interest paid	(3,315,765)	(3,084,667)
Interest received	442,689	348,703
Net cash from operating activities	15,470,963	12,055,575
Investing activities		
Purchase of property, plant and equipment	(17,090,977)	(12,379,044)
Proceeds on disposal of property, plant and equipment	34,468	52,120
Purchase of intangible assets	(3,500,329)	(1,278,039)
Net cash used by investing activities	(20,556,838)	(13,604,963)
Investing activities		
Purchase of property, plant and equipment	(17,090,977)	(12,379,044)
Proceeds on disposal of property, plant and equipment	34,468	52,120
Purchase of intangible assets	(3,500,329)	(1,278,039)
Net cash used by investing activities	(20,556,838)	(13,604,963)
Financing activities		
Dividends paid	(2,600,000)	(3,350,000)
Proceeds from long-term debt	-	7,000,000
Repayment of long-term debt	(1,273,257)	(858,480)
Repayment of lease liabilities	(197,224)	(156,757)
Net cash used by financing activities	(4,070,481)	2,634,763
Change in cash	(9,156,356)	1,085,375
Cash, beginning of year	14,812,404	13,727,029
Cash, end of year	$ 5,656,048	$ 14,812,404

Amping up to celebrate

Burlington Hydro is an engaged and responsive company with roots that are deeply entrenched in the community it serves.

Electricity first came to Burlington in the early 1900s, delivered into the community by a number of privately owned and provincial power companies. As Burlington grew, so did its power system. It wasn't until 1945 however, that the Town took over the reins and created the Burlington Public Utilities Commission (PUC), the predecessor to Burlington Hydro.

2020 marks an important milestone for Burlington Hydro. We'll be celebrating a long-standing 75 year tradition of service to our community. And while recognizing our past, we'll also pay tribute to today's company with a glimpse into what our future holds.

We're planning a grand celebration! It will include a specially produced video that pays tribute to our 75th Anniversary. We'll launch a special celebratory section on our website and then in the fall we're planning a special public Open House, opening our doors to celebrate with our customers and our community. We're looking forward to the celebration!

Photo caption: Photo Credit here

burlingtonhydro.com

@burlingtonhydro

gridsmartcity.com

1340 Brant Street, Ontario L7R 2Z7 | 905 332 1851

From:	registrar
To:	Shelly-Anne Connell
Subject:	Letter of Comment, Burlington Hydro"s application number EB-2020-0007
Date:	Tuesday, December 1, 2020 5:30:57 PM

From: Elizabeth Day [redacted]
Sent: Monday, November 30, 2020 1:10 PM
To: BoardSec <BoardSec@oeb.ca>
Subject: Burlington Hydro's application number EB-2020-0007

Good afternoon,

Regarding any rate increase put to consumers at this time:

I can barely afford hydro rates now, as Ontario hydro has increased their off peak hour and overall rates by 2%.

To review rates every 5 years is appropriate, but changing distribution rates in the years of a global pandemic is not right. Many, many are out of work and struggling to get by.

Please reconsider increasing distribution rates in perhaps 2-3 years.

Yours truly
Burlington Hydro Consumer

Attention: Elizabeth Day
VIA EMAIL

December 21, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Ms. Day,

Thank you for your Letter of Comment submitted to the Ontario Energy Board ("OEB") with respect to the rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You expressed in your letter that Burlington Hydro should not be proposing a distribution rate increase in the midst of a global pandemic. The proposed distribution rate increase in May 2021 is the result of two years of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations. Distribution rates account for approximately 26% of the entire electricity bill.

As you mentioned, Burlington Hydro submits this type of application - a Cost of Service application - to the OEB once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in residential rates beyond inflation is required in 2021 to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g., poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan. Attached is a brief summary of our Application to provide you with some more information.

The OEB will only approve an increase to distribution rates if Burlington Hydro can provide adequate evidence to support the capital and operating costs that are contributing to the increase. Various intervenor groups, made up of experts who act on behalf of customers, will also review the application and may challenge the proposed rate changes.

There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program ("CEAP"), the Ontario Electricity Support Program ("OESP"), the Low-Income Energy Assistance Program ("LEAP") and the Affordability Fund Trust ("AFT"). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

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Burlington**hydro** inc.

In addition, eligible customers are now able to choose between Time-of Use and Tiered electricity rates, which make up 43% of the average residential electricity bill. These rates are set by the OEB. Depending on how and when you use electricity, changing your electricity price plan may save you money on your electricity bill. More information is available on our website at:
https://www.burlingtonhydro.com/billing/time-of-use-customer-choice-landing.html

Thank you again for your comments and please contact us with any further questions or concerns.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

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GridSmartCity

Partner since 2009

BURLINGTON HYDRO'S 2021- 2025 RATE APPLICATION

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Between 2014 and 2020, BHI invested in replacing deteriorated distribution system assets such as wood poles and transformers in order to reduce the frequency and duration of unplanned outages. Capacity upgrades were made to accommodate growth in North East Burlington and vertical growth in downtown Burlington. Investments were made in new computer software systems, including BHI's Customer Information System which empowers customers with more self-service options and solutions to help manage and monitor energy use.

BHI developed its business plan based on information and input from internal engineering and technical experts, who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans. The plan also considers BHI's legal and statutory requirements as a regulated utility.

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Over the course of the 2021-2025 period, BHI's investment needs are driven by deteriorating infrastructure, ongoing demand for new connections to the grid, changing electricity demand in pockets of the city, and technology changes.

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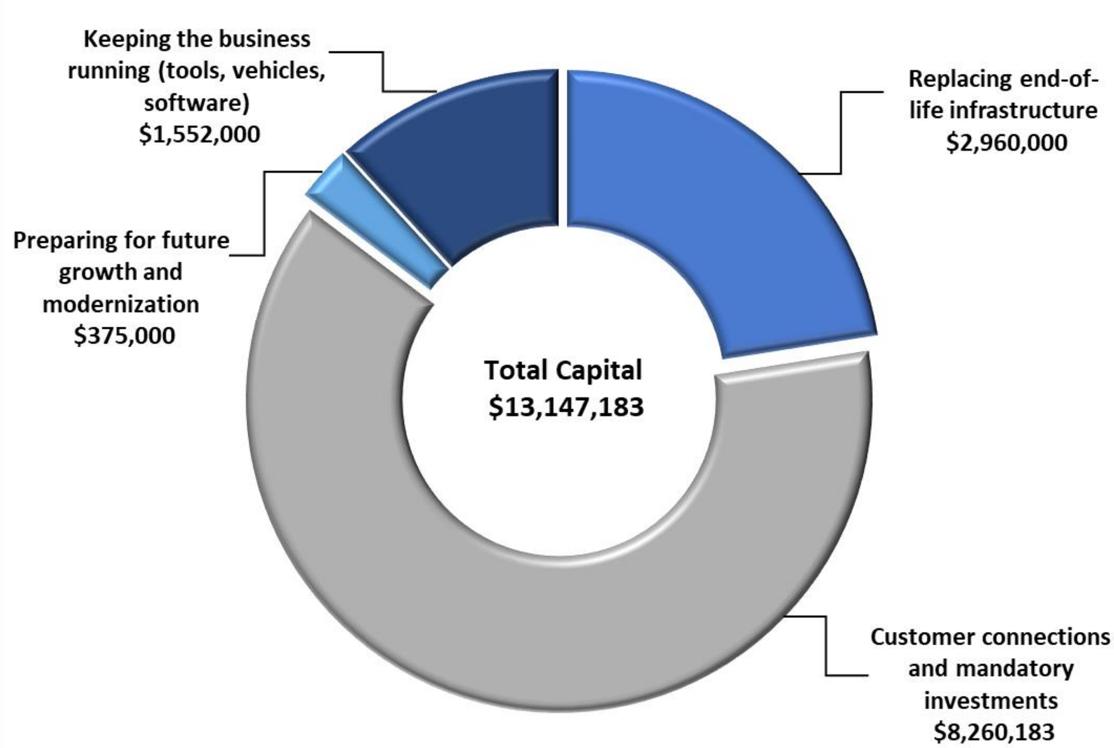
- Investing in grid resiliency and BHI's ability to respond to more frequent occurrences of adverse weather events;
- Ensuring sufficient short-term and long-term system capacity is available to meet customer demand;
- Meeting the utility's obligation to accommodate customer connections (e.g. new subdivisions, condo developments) and comply with other mandated service requirements (e.g. relocating poles due to road widening);
- Making prudent investments into non-distribution system assets (e.g. tools, vehicles, software) to enhance service offerings and support resource planning; and
- Maintaining a focus on continuous improvement, efficiency, and productivity.

HOW MUCH WILL BHI'S PLAN COST?

BHI's proposed capital investments in 2021 are $13,147,183. Proposed operating expenditures in 2021 are $21,497,775.



BHI Bill Breakdown

Electricity distributors like BHI are funded through the distribution rates paid by customers. BHI does not receive taxpayer money to fund its operations or investments in the distribution system. While BHI is responsible for collecting payment for the entire electricity bill, it retains only a portion of the delivery charge representing approximately 25% of the bill (see page 4).

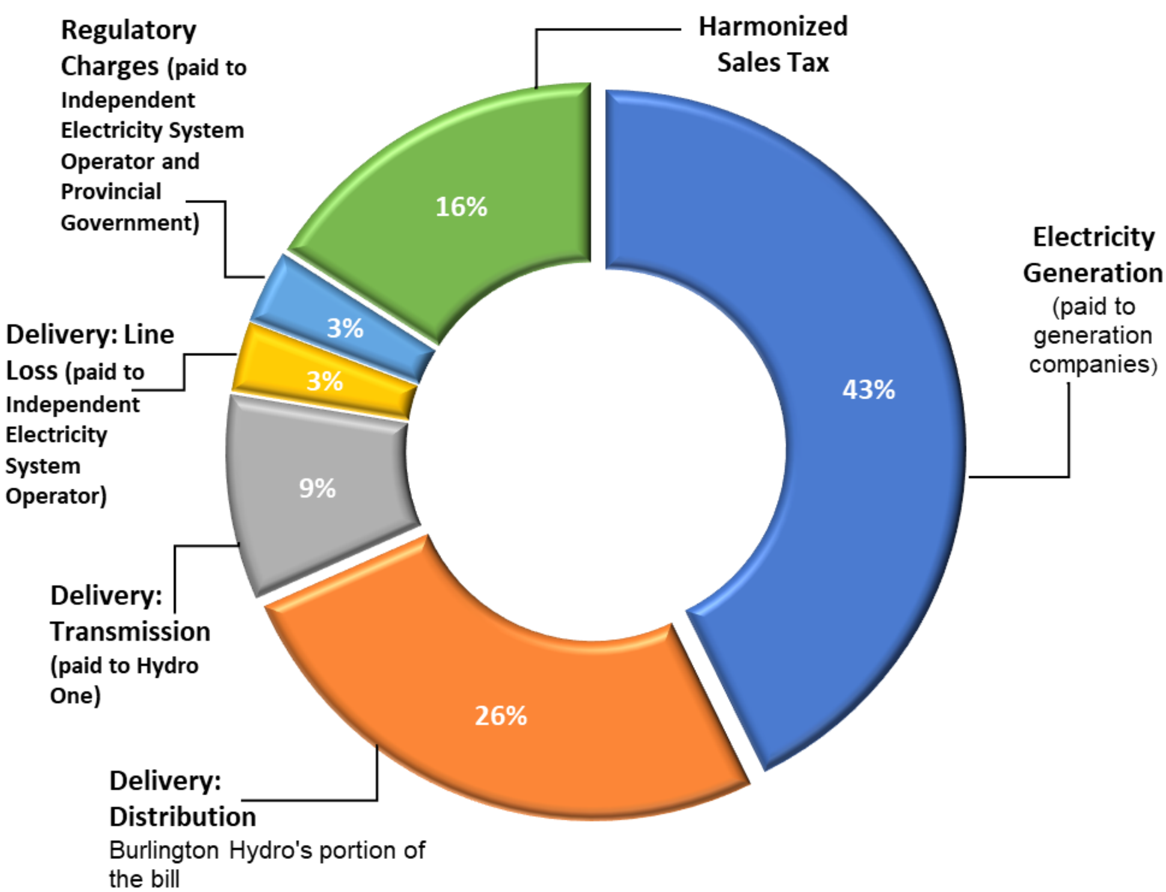
The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

Customer (Rate Class)	kWh Usage per Month	Total Bill Impact	
		$	%
Residential	750	$2.46	2.1%
General Service<50 kW	2,000	$6.34	2.2%

The Ontario Energy Board and intervenors representing various customer groups such as low-income consumers, school boards and commercial and industrial customers will review BHI's plan in a rigorous, transparent public hearing process.

BILL BREAKDOWN

These are the electricity charges for the average residential customer using 750 kWh per month. These percentages include the Ontario Electricity Rebate.



How to Stay Involved

For more information or to access BHI's complete application visit: https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

For more information on how to participate visit https://www.oeb.ca/participate.

From:	registrar
To:	Shelly-Anne Connell
Subject:	Letter of Comment, EB-2020-0007 rate change applications concerns
Date:	Friday, December 4, 2020 9:18:36 AM

From: Hendrika Slagter [redacted]
Sent: Thursday, December 3, 2020 2:43 PM
To: IndustryRelations@ontarioenergyboard.ca <IndustryRelations@oeb.ca>
Subject: Fwd: rate change applications concerns

John Slagter [redacted]

To the OEB
Re: Burlington Hydro Inc Rate Change Application

It is quite nervy to make such a request as applied for and I am totally opposed to be granted this approval from OEB for reasons such as this:
Firstly, all charges are increased, and written applications will be extended to charge non-carriers a different pole attachment charge for access to its power poles. That cost will of course in time be passed on also to the consumer, which is not mentioned yet.
In times like this, which are already stressful, do not allow the Burlington Hydro inc. to increase charges.
This past year short blackouts during the day and night have occurred for whatever reason, is this going to be normal like California? If Burlington is short of funds, they may want to consider saving by using their cars, trucks, etc. for a longer time, as we must not spend beyond their means on new vehicles every year. The service of Burlington Hydro needs a lot to be desired, it appears outside contractors are filling in for Burlington Hydro why?
As a public service they need to clean-up. Perhaps they should defund inside and outside workers.
The office building/staff is operated as if it's "Fort Knox." To obtain rushed technical information from engineering is non existing, when approaching someone from Burlington Hydro in a vehicle for a question, how to contact someone in the office, they do not know.
Burlington Hydro better get their act together, I am sure they get paid well, thus let them show some work in the field in a timely manner.
Thank you for listening.

Burlington**hydro** inc.

Attention: John Slagter
VIA EMAIL

December 21, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Mr. Slagter,

Thank you for your Letter of Comment submitted to the Ontario Energy Board ("OEB") with respect to the rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You expressed in your letter that you are opposed to the request to increase distribution rates. The proposed distribution rate increase in May 2021 is the result of two years of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations. Distribution rates account for approximately 26% of the entire electricity bill.

We understand that there is never an ideal time for a rate increase, and that it is particularly difficult in the midst of the COVID-19 pandemic. Burlington Hydro submits this type of application - a Cost of Service application - to the OEB once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in residential rates beyond inflation is required in 2021 to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g., poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan. Attached is a brief summary of our Application to provide you with some more information.

You mention concerns about spending and reliability. Burlington Hydro only replaces infrastructure and equipment, including vehicles, when required. We employ contractors in various circumstances to complete certain tasks as it is more cost effective and efficient than hiring employees on a full-time basis. I can also assure you that one of Burlington Hydro's top priorities is the reliable distribution of electricity. Our target over the next five years is to limit customer outages to no more than an average of 1.2 hours per year per customer excluding major events such as storms.

The OEB will only approve an increase to distribution rates if Burlington Hydro can provide adequate evidence to support the capital and operating costs that are contributing to the increase. They will also review the appropriateness and impact to all customers of proposed changes in other revenue, such as the pole attachment charges you mentioned in your letter.

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Burlington**hydro** inc.

Various intervenor groups, made up of experts who act on behalf of customers, will also review the application and may challenge the proposed rate changes.

There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program ("CEAP"), the Ontario Electricity Support Program ("OESP"), the Low-Income Energy Assistance Program ("LEAP") and the Affordability Fund Trust ("AFT"). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

In addition, eligible customers are now able to choose between Time-of Use and Tiered electricity rates, which make up 43% of the average residential electricity bill. These rates are set by the OEB. Depending on how and when you use electricity, changing your electricity price plan may save you money on your electricity bill. More information is available on our website at:
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Thank you again for your comments and please contact us at 905-332-1851 with any further questions or concerns you may have.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

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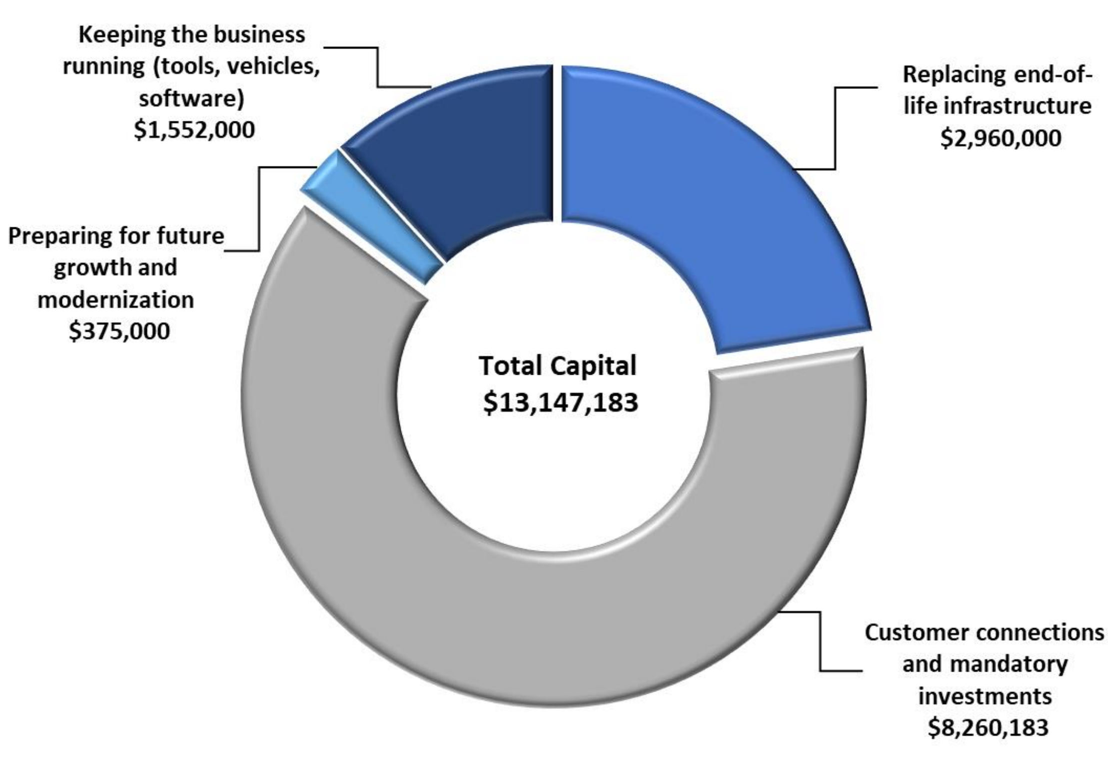

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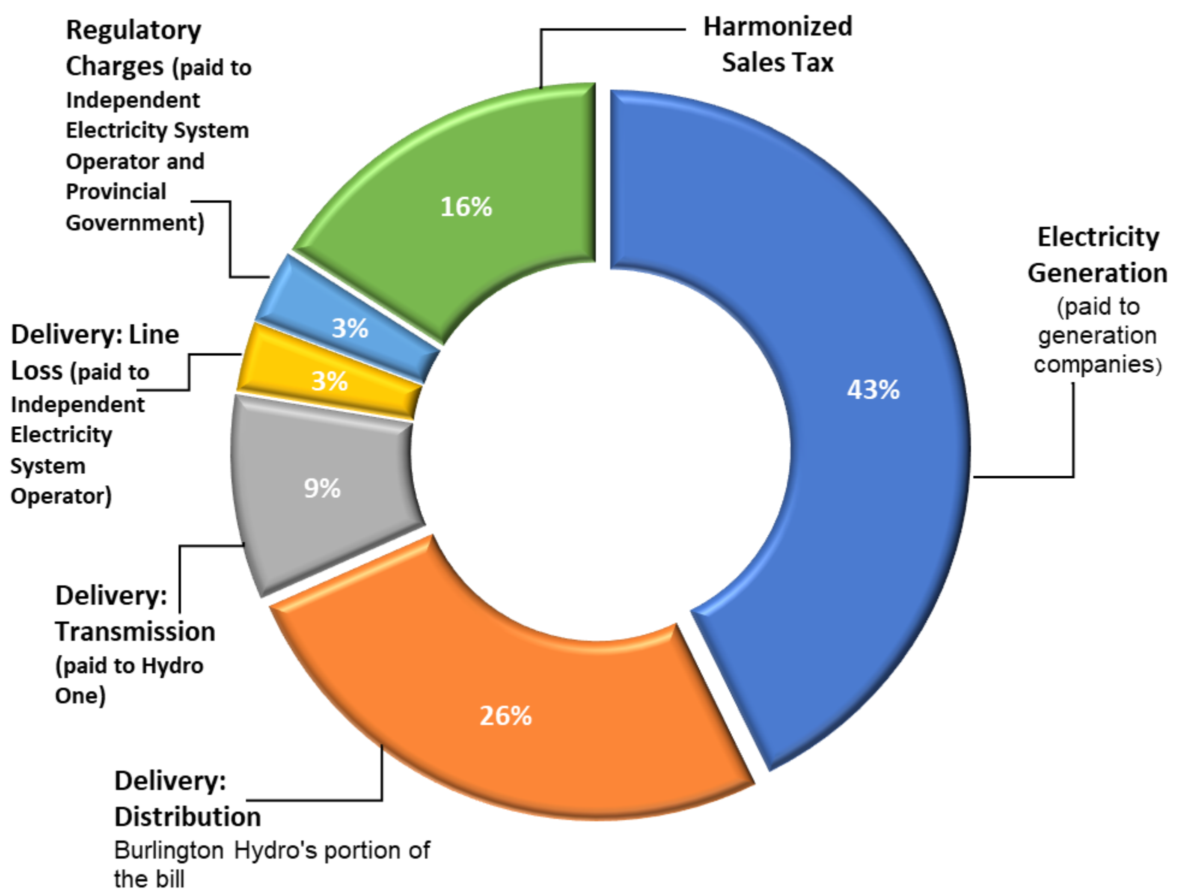

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From: registrar
To: Shelly-Anne Connell
Subject: Letter of Comment, EB-2020-0007 FW: OEB notice to increase rates 2021 intervenor
Date: Friday, December 4, 2020 9:09:38 AM

From: Jacqueline Jowahir [redacted]
Sent: Thursday, December 3, 2020 11:12 AM
To: registrar <registrar@oeb.ca>
Subject: OEB notice to increase rates 2021 intervenor

To whom it may concern,

given that we are in unprecedented times here in Burlington and worldwide, consideration should be taken into account to reconsider increasing rates in such times.

Residents are struggling with job losses, income sources, etc. and we truly don't know what impact this pandemic will truly have until such time as the government ceases to provide financial assistance. This will only come into light until 2021, and to increase rates in such a time when people are struggling to provide basic needs for their respective families, would be highly insensitive.

I strongly believe that we should not put profits over people in such unprecedented times with the COVID pandemic.

Burlington Hydro, as well as all levels of businesses and government should be working together for the benefit of the people at this time.

There is no harm in considering this rate increase come late 2021 when we will have a better perspective on the economic circumstances.

Sincerely,

--
Jacqueline Jowahir
Burlington resident

Burlingtonhydro inc.

Attention: Jacqueline Jowahir
VIA EMAIL

December 21, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Ms. Jowahir,

Thank you for your Letter of Comment submitted to the Ontario Energy Board ("OEB") with respect to the rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You expressed in your letter that Burlington Hydro should reconsider increasing rates in such unprecedented times. The proposed distribution rate increase in May 2021 is the result of two years of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations. Distribution rates account for approximately 26% of the entire electricity bill.

We understand that there is never an ideal time for a rate increase, and that it is particularly difficult in the midst of the COVID-19 pandemic. Burlington Hydro submits this type of application - a Cost of Service application - to the OEB once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in residential rates beyond inflation is required in 2021 to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g., poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan. Attached is a brief summary of our Application to provide you with some more information.

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You have also suggested that Burlington Hydro should be working with businesses and government for the benefit of the people at this time. There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program ("CEAP"), the Ontario Electricity Support Program ("OESP"), the Low-Income Energy Assistance Program ("LEAP") and the Affordability Fund Trust ("AFT"). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

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GridSmartCity
Partner since 2009

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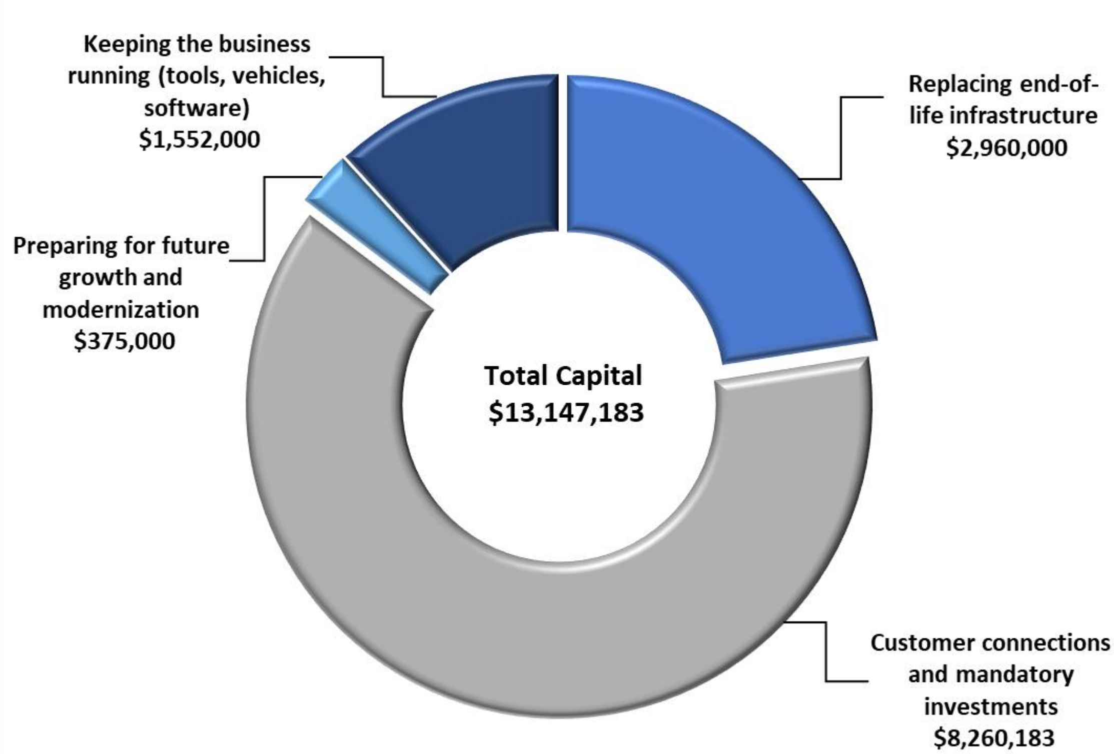
- Ensuring sufficient short-term and long-term system capacity is available to meet customer demand;
- Meeting the utility's obligation to accommodate customer connections (e.g. new subdivisions, condo developments) and comply with other mandated service requirements (e.g. relocating poles due to road widening);
- Making prudent investments into non-distribution system assets (e.g. tools, vehicles, software) to enhance service offerings and support resource planning; and
- Maintaining a focus on continuous improvement, efficiency, and productivity.

HOW MUCH WILL BHI'S PLAN COST?

BHI's proposed capital investments in 2021 are $13,147,183. Proposed operating expenditures in 2021 are $21,497,775.



BHI Bill Breakdown

Electricity distributors like BHI are funded through the distribution rates paid by customers. BHI does not receive taxpayer money to fund its operations or investments in the distribution system. While BHI is responsible for collecting payment for the entire electricity bill, it retains only a portion of the delivery charge representing approximately 25% of the bill (see page 4).

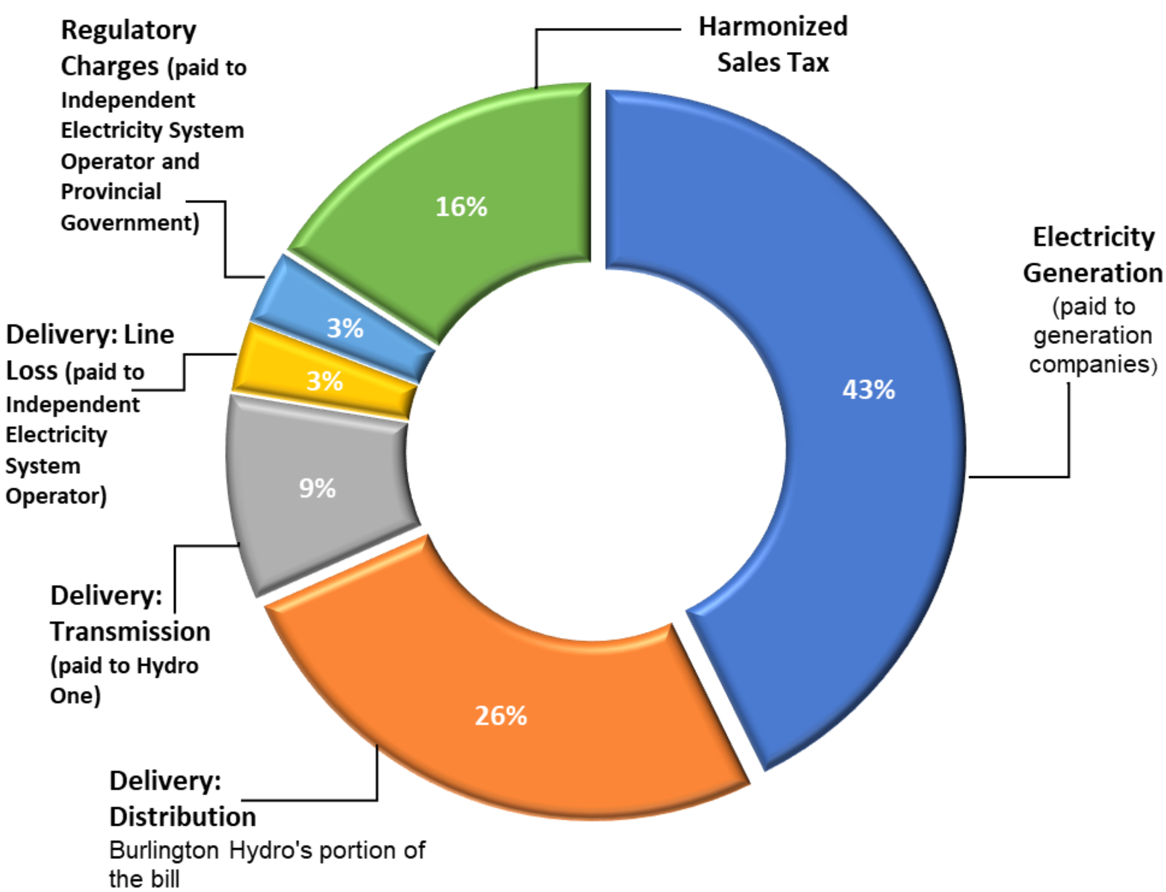
The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

Customer (Rate Class)	kWh Usage per Month	Total Bill Impact	
		$	%
Residential	750	$2.46	2.1%
General Service<50 kW	2,000	$6.34	2.2%

The Ontario Energy Board and intervenors representing various customer groups such as low-income consumers, school boards and commercial and industrial customers will review BHI's plan in a rigorous, transparent public hearing process.

BILL BREAKDOWN

These are the electricity charges for the average residential customer using 750 kWh per month. These percentages include the Ontario Electricity Rebate.



How to Stay Involved

For more information or to access BHI's complete application visit: https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

For more information on how to participate visit https://www.oeb.ca/participate.

From: registrar
To: Shelly-Anne Connell
Subject: FW: Letter of Comment -EB-2020-0007
Date: Friday, December 4, 2020 9:14:13 AM

-----Original Message-----
From: Webmaster <Webmaster@oeb.ca>
Sent: Thursday, December 3, 2020 1:25 PM
To: registrar <registrar@oeb.ca>
Subject: Letter of Comment - [redacted]

The Ontario Energy Board

-- Comment date --
2020-12-03

-- Case Number --
EB-2020-0007

-- Name --
Ana Carolina Marcondes

-- Phone --
[redacted]

-- Company --

-- Address --
[redacted]

-- Comments --
Hello,
I'd like to suggest that Burlington Hydro provides the items below so that residents can have a clear view and be able to comment about this case:

1) Summary of breakdown cost in plain language
2) Sustainable plan/business case for residents who have financial constraint due to the pandemic situation (e.g. lost a job)
3) Show financial summary including the cost increase and clarifying that this is not profit or cost recovery related. That should happen only when all is good and economy is recovered.
4) How does it relate to the recent increase using a flat rate for 4 months that ended in October 2020

Thanks

-- Attachment --

Burlington**hydro** inc.

Attention: Ana Carolina Marcondes
VIA EMAIL

December 21, 2020

Re: Burlington Hydro Inc.'s 2021 Cost of Service Application (EB-2020-0007)

Dear Ms. Marcondes,

Thank you for your Letter of Comment submitted to the Ontario Energy Board ("OEB") with respect to the rate increase proposed for May 1, 2021 in Burlington Hydro's Cost of Service Rate Application ("the Application"). We value all customer feedback and the time you took to submit your comments.

You suggested in your letter that Burlington Hydro provide some more information so that residents can have a clear view of the Application; and suggested that the rate increase be deferred until the economy is recovered. The proposed rate increase in May 2021 relates to distribution rates which recover the cost to maintain and operate the local electricity distribution system serving Burlington Hydro residents. Distribution rates account for approximately 26% of the entire electricity bill. This increase is unrelated to the Time of Use prices you mentioned in your letter; which were increased on November 1. These rates represent the cost of electricity on a per kWh basis and are set by the OEB.

Our Application is the result of two years of careful planning to address and appropriately balance the needs and preferences of our customers, our distribution system requirements, and public policy obligations. Burlington Hydro submits this type of application - a Cost of Service application - to the OEB once every five years on average. Our last Cost of Service application was in 2014. Since that time, we have increased distribution rates annually at lower than the rate of inflation. However, Burlington Hydro has identified that an increase in distribution rates beyond inflation is required in 2021 to continue to safely and reliably distribute electricity. A large percentage of our distribution infrastructure (e.g., poles, transformers, overhead wire and underground cable) was installed in the 1980s and requires replacement over the next five years. We consulted with customers in 2019 through on-line and telephone surveys and the majority of customers surveyed supported Burlington Hydro's proposed five-year plan.

Attached is a brief summary of our Application to provide you with some more information. The entire Application is also posted on our website at:

https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs/distribution-rates-and-charges.html

Exhibit 1 may provide you with more of the information you are looking for, specifically the Key Elements of our Application on page 31 and the Application Summary on page 76 may address the items you would like to see, such as a breakdown of cost and a financial summary.

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

Burlington**hydro** inc.

The OEB will only approve an increase to distribution rates if Burlington Hydro can provide adequate evidence to support the capital and operating costs that are contributing to the increase. Various intervenor groups, made up of experts who act on behalf of customers, will also review the application and may challenge the proposed rate changes.

You mentioned the need for a sustainable plan for residents who have financial constraints due to the pandemic. There is assistance available for individuals and families struggling to pay their electricity bills such as the COVID-19 Energy Assistance Program ("CEAP"), the Ontario Electricity Support Program ("OESP"), the Low-Income Energy Assistance Program ("LEAP") and the Affordability Fund Trust ("AFT"). More details on these programs can be provided by contacting one of our Customer Service Representatives if required.

In addition, eligible customers are now able to choose between Time-of Use and Tiered electricity rates, which make up 43% of the average residential electricity bill. Depending on how and when you use electricity, changing your electricity price plan may save you money on your electricity bill. More information is available on our website at:
https://www.burlingtonhydro.com/billing/time-of-use-customer-choice-landing.html

Thank you again for your comments and please contact us with any further questions or concerns.

Yours truly,

Sally Blackwell, MBA, CPA, CMA
Vice President Regulatory Compliance and Asset Management

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

GridSmartCity Partner since 2009

BURLINGTON HYDRO'S 2021- 2025 RATE APPLICATION

About BURLINGTON HYDRO

Burlington Hydro Inc. ("BHI") is a local distribution company serving approximately 68,000 residential and commercial customers in the City of Burlington. BHI is responsible for distributing power from the provincial transmission grid safely and reliably to homes and businesses across its service territory. The company is wholly owned by the City of Burlington.

BHI's 2021-2025 Business Plan

BHI has applied to the Ontario Energy Board for a change in the distribution rates that it charges its customers, effective May 1, 2021. The distribution rates are based on BHI's business plan, which includes capital investments (e.g. poles and wires) as well as operating expenses for day-to-day management of the company (e.g. customer service and outage response).

Between 2014 and 2020, BHI invested in replacing deteriorated distribution system assets such as wood poles and transformers in order to reduce the frequency and duration of unplanned outages. Capacity upgrades were made to accommodate growth in North East Burlington and vertical growth in downtown Burlington. Investments were made in new computer software systems, including BHI's Customer Information System which empowers customers with more self-service options and solutions to help manage and monitor energy use.

BHI developed its business plan based on information and input from internal engineering and technical experts, who closely monitor the pressures on the distribution system, develop solutions to address these challenges, and recommend investments that inform its plans. The plan also considers BHI's legal and statutory requirements as a regulated utility.

How Customers Informed BHI's Plans

BHI engaged customers throughout the development of its 2021-2025 business plan to inform and solicit feedback on the proposals being considered and associated outcomes expected. Between June 2019 and January 2020, BHI gathered feedback from close to 5,000 residential, small business and commercial customers through its customer engagement efforts.

BHI's Plan Delivers Outcomes to Customers

Over the course of the 2021-2025 period, BHI's investment needs are driven by deteriorating infrastructure, ongoing demand for new connections to the grid, changing electricity demand in pockets of the city, and technology changes.

BHI's capital and operating plans are focused on the following activities and customer outcomes:

- Renewing deteriorating infrastructure to maintain the reliability and safety of the system;
- Investing in grid resiliency and BHI's ability to respond to more frequent occurrences of adverse weather events;
- Ensuring sufficient short-term and long-term system capacity is available to meet customer demand;
- Meeting the utility's obligation to accommodate customer connections (e.g. new subdivisions, condo developments) and comply with other mandated service requirements (e.g. relocating poles due to road widening);
- Making prudent investments into non-distribution system assets (e.g. tools, vehicles, software) to enhance service offerings and support resource planning; and
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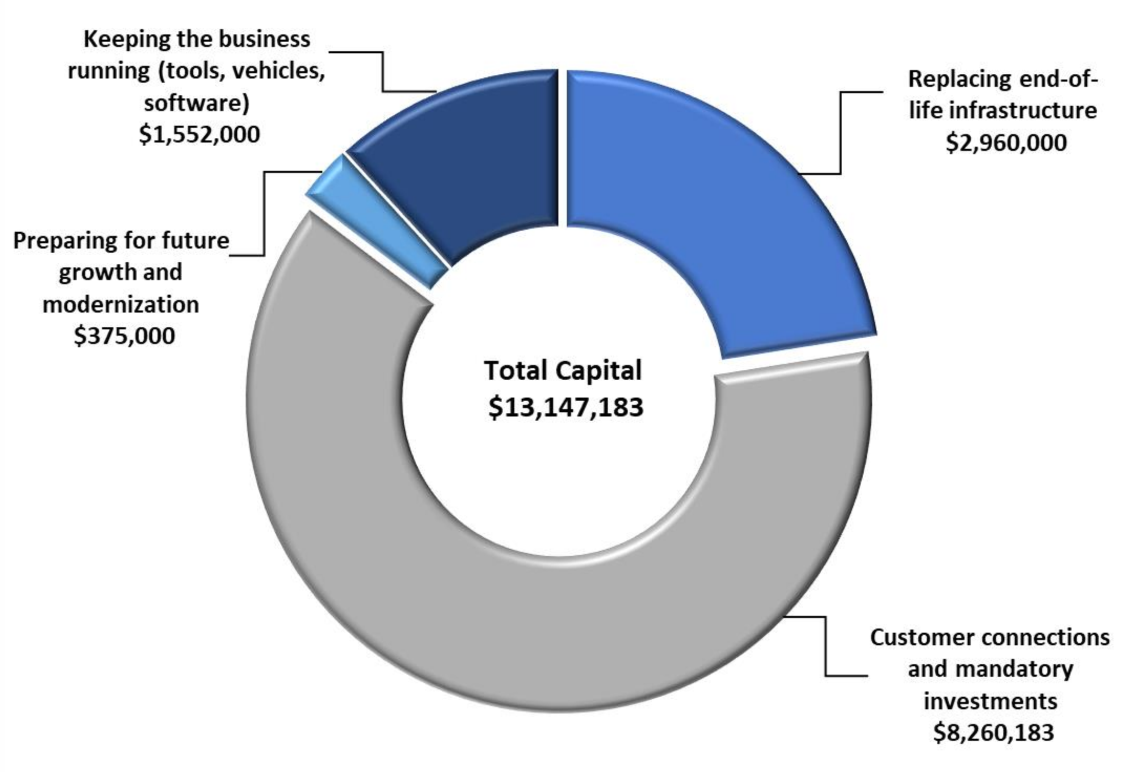

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The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

Customer (Rate Class)	kWh Usage per Month	Total Bill Impact	
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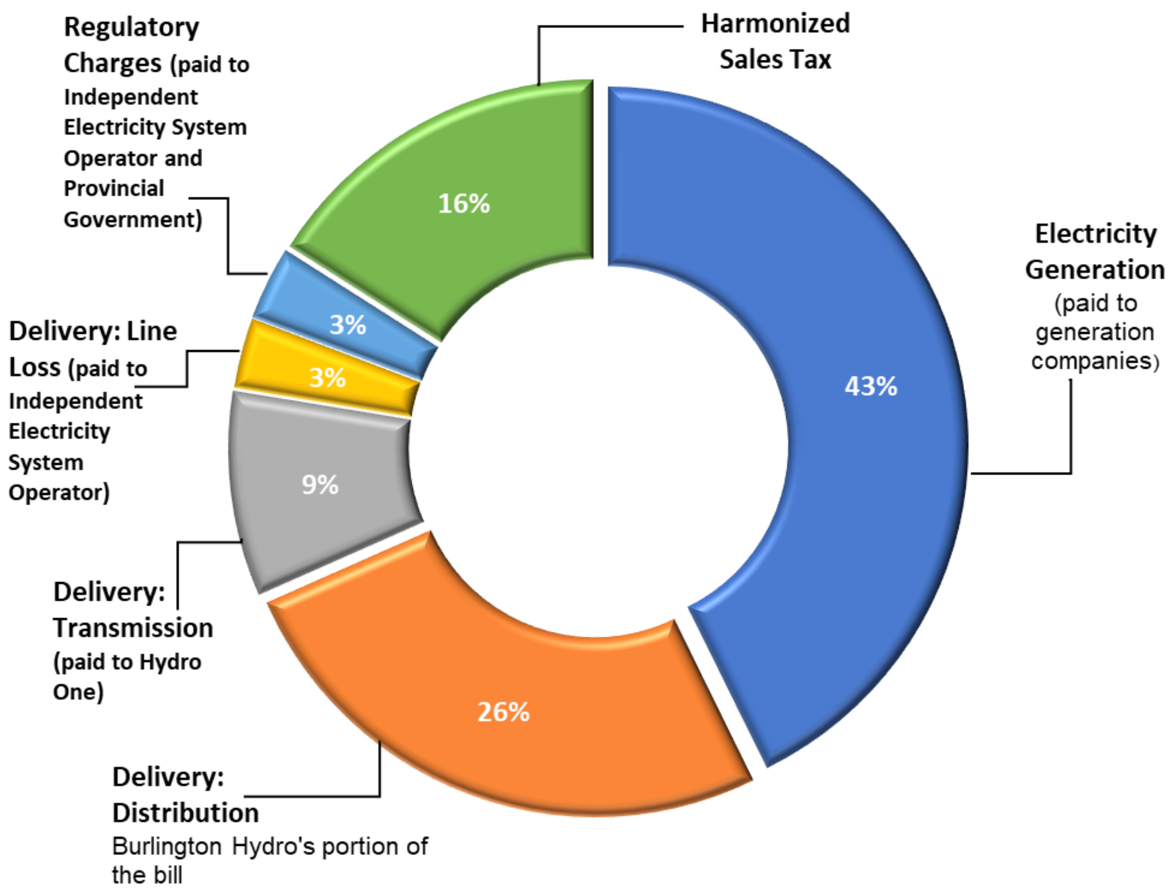

How to Stay Involved

For more information or to access BHI's complete application visit: https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

For more information on how to participate visit https://www.oeb.ca/participate.

APPENDIX B: 4-Staff-61 a)

Canada Revenue Agency | Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2019-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes				-1,524,915	A
Deduct: (increase a loss)					
Net capital losses deducted in the year (enter as a positive amount)			a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			d		
Amount of an employer for non-qualified securities under an employee stock options agreement deductible under paragraph 110(1)(e)			1d		
Subtotal (total of amounts a to 1d)			▶		B
Subtotal (amount A **minus** amount B; if positive, enter "0")				-1,524,915	C
Deduct: (increase a loss)					
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions					D
Subtotal (amount C **minus** amount D)				-1,524,915	E
Add: (decrease a loss)					
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)					F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0")				-1,524,915	G

If amount G is negative, enter it on line 110 as a positive.

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year			e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102		▶		H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110	1,524,915	h		
Subtotal (amount g **plus** amount h)		1,524,915	▶	1,524,915	I
Subtotal (amount H **plus** amount I)				1,524,915	J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

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Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130		k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l		
Subtotal (total of amounts i to l)			▶		K
Non-capital losses before any request for a carryback (amount J **minus** amount K)				1,524,915	L

Deduct – Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903	1,524,915	o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)		1,524,915	▶	1,524,915	M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180				N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200	85,869	a		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)		85,869	▶	85,869	A

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)				85,869	C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)	210				D
Unused non-capital losses that expired in the tax year (note 4)			e		
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220				E
Subtotal (total of amounts C to E)				85,869	F

Note

If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

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Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6)			225		G
Capital losses before any request for a carryback (amount F **minus** amount G)				85,869	H

Deduct – **Request to carry back capital loss to** (note 7):

	Capital gain (100%)		Amount carried back (100%)			
First previous tax year		951		h		
Second previous tax year		952		i		
Third previous tax year		953		j		
Subtotal (total of amounts h to j)				▶		I
Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I)					280 85,869	J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			a		
Deduct: Farm loss expired (note 8)	300		b		
Farm losses at the beginning of the tax year (amount a **minus** amount b)	302		▶		A
Add:					
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305		c		
Current-year farm loss (amount F in Part 1)	310		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	350		e		
Section 80 – Adjustments for forgiven amounts	340		f		
Farm losses of previous tax years applied in the current tax year Enter amount g on line 334 of the T2 Return.	330		g		
Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9)	335		h		
Subtotal (total of amounts e to h)			▶		D
Farm losses before any request for a carryback (amount C **minus** amount D)					E
Deduct – **Request to carry back farm loss to:**					
First previous tax year to reduce taxable income	921		i		
Second previous tax year to reduce taxable income	922		j		
Third previous tax year to reduce taxable income	923		k		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		l		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		m		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		n		
Subtotal (total of amounts i to n)			▶		F
Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F)				380	G

Note 8: A farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

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Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business		485		A
Minus the deductible farm loss:				
(amount A above ______ – $2,500) **divided** by 2 = ______ a				
Amount a or $ 15,000 (note 10), whichever is less			b	
	2,500	c		
Subtotal (amount b **plus** amount c)	2,500		2,500	B
Current-year restricted farm loss (amount A **minus** amount B)				C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d		
Deduct: Restricted farm loss expired (note 11)	400		e		
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402				D
Add:					
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405		f		
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	410		g		
Subtotal (amount f **plus** amount g)					E
Subtotal (amount D **plus** amount E)					F
Deduct:					
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	430		h		
Section 80 – Adjustments for forgiven amounts	440		i		
Other adjustments	450		j		
Subtotal (total of amounts h to j)					G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)					H
Deduct – **Request to carry back restricted farm loss to:**					
First previous tax year to reduce farming income	941		k		
Second previous tax year to reduce farming income	942		l		
Third previous tax year to reduce farming income	943		m		
Subtotal (total of amounts k to m)					I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480				J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

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Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)			510		B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains	530		c		
Enter amount c on line 655 of Schedule 6.					
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back listed personal property loss to:					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)			580		G

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Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership account number 600	Tax year ending yyyy/mm/dd 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) 620
1.						
					Total (enter this amount on line 222 of Schedule 1)	

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership account number 630	Tax year ending yyyy/mm/dd 632	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650
1.						

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership account number 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary 664	Current-year limited partnership losses (from line 620) 670	Limited partnership losses applied in the current year (must be equal to or less than line 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) 680
1.					
			Total (enter this amount on line 335 of the T2 return)		

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

COPY

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	1,524,915		1,524,915	N/A		
1st preceding taxation year 2018-12-31		N/A		N/A			
2nd preceding taxation year 2017-12-31		N/A		N/A			
3rd preceding taxation year 2016-12-31		N/A		N/A			
4th preceding taxation year 2015-12-31		N/A		N/A			
5th preceding taxation year 2014-12-31		N/A		N/A			
6th preceding taxation year 2013-12-31		N/A		N/A			
7th preceding taxation year 2012-12-31		N/A		N/A			
8th preceding taxation year 2011-12-31		N/A		N/A			
9th preceding taxation year 2010-12-31		N/A		N/A			
10th preceding taxation year 2009-12-31		N/A		N/A			
11th preceding taxation year 2008-12-31		N/A		N/A			
12th preceding taxation year 2007-12-31		N/A		N/A			
13th preceding taxation year 2006-12-31		N/A		N/A			
14th preceding taxation year 2005-12-31		N/A		N/A			
15th preceding taxation year 2004-12-31		N/A		N/A			
16th preceding taxation year 2003-12-31		N/A		N/A			
17th preceding taxation year 2002-12-31		N/A		N/A			
18th preceding taxation year 2001-12-31		N/A		N/A			
19th preceding taxation year 2001-09-30		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total		1,524,915		1,524,915			

* **This balance expires this year and will not be available next year.**

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APPENDIX C: 4-Staff-62 c)

Burlington Hydro Inc.
Impact of Bill 97 - Accelerated Rate Tax Depreciation
Per OEB Accounting Guidance Dated July 25, 2019
Comparison of 1.5x to 1.0x in 2024 and 2025

2024

	Rate	CCA Class	Opening	Addition	AIIP	CCA	Ending
	6%	1b		495,000	495,000	44,550	450,450
	20%	8		51,500	51,500	15,450	36,050
	30%	10		300,000	300,000	135,000	165,000
1.5	100%	12		766,370	766,370	766,370	-
	8%	47		11,485,497	11,485,497	1,378,260	10,107,237
	55%	50		50,000	50,000	41,250	8,750
		Total	-	13,148,367	13,148,367	2,380,880	10,767,487

2025

CCA Class	Opening	Addition	AIIP	CCA	Ending
1b	450,450			27,027	423,423
8	36,050			7,210	28,840
10	165,000			49,500	115,500
12	-			-	-
47	10,107,237			808,579	9,298,658
50	8,750			4,813	3,938
Total	10,767,487	-	-	897,128	9,870,359

Total

		CCA Class	Opening	Addition	AIIP	CCA	Ending
	6%	1b					
	20%	8					
	30%	10					
1.5	100%	12					
	8%	47					
	55%	50					
		Total	-	-		-	-

CCA Class	Opening	Addition	AIIP	CCA	Ending
1b		495,000	495,000	44,550	450,450
8		51,500	51,500	15,450	36,050
10		300,000	300,000	135,000	165,000
12		766,370	766,370	766,370	-
47		11,485,497	11,485,497	1,378,260	10,107,237
50		50,000	50,000	41,250	8,750
Total	-	13,148,367	13,148,367	2,380,880	10,767,487

	2024	2025	Total
SUM OF CCA - 1.5x	2,380,880	3,278,008	5,658,888

	Rate	CCA Class	Opening	Addition	AIIP	CCA	Ending
	6%	1b		495,000	495,000	29,700	465,300
	20%	8		51,500	51,500	10,300	41,200
	30%	10		300,000	300,000	90,000	210,000
1	100%	12		766,370	766,370	766,370	-
	8%	47		11,485,497	11,485,497	918,840	10,566,657
	55%	50		50,000	50,000	27,500	22,500
		Total	-	13,148,367	13,148,367	1,842,710	11,305,657

CCA Class	Opening	Addition	AIIP	CCA	Ending
1b	465,300			27,918	437,382
8	41,200			8,240	32,960
10	210,000			63,000	147,000
12	-			-	-
47	10,566,657			845,333	9,721,325
50	22,500			12,375	10,125
Total	11,305,657	-	-	956,866	10,348,792

		CCA Class	Opening	Addition	AIIP	CCA	Ending
	6%	1b					
	20%	8					
	30%	10					
1	100%	12					
	8%	47					
	55%	50					
		Total	-	-		-	-

CCA Class	Opening	Addition	AIIP	CCA	Ending
1b		495,000	495,000	29,700	
8		51,500	51,500	10,300	41,200
10		300,000	300,000	90,000	210,000
12		766,370	766,370	766,370	-
47		11,485,497	11,485,497	918,840	10,566,657
50		50,000	50,000	27,500	22,500
Total	-	13,148,367	13,148,367	1,842,710	10,840,357

	2024	2025	Total
SUM OF CCA - 1.0x	1,842,710	2,799,575	4,642,285
DECREASE IN CCA	(538,170)	(478,433)	(1,016,603)
Tax Rate	26.50%	26.50%	26.50%
TAX IMPACT	(142,615)	(126,785)	(269,400)

APPENDIX D: 4-Staff-62 c)

Burlington Hydro Inc.
Impact of Bill 97 - Accelerated Rate Tax Depreciation
Account 1592 - Smoothing Impact

Rate Setting Year:	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
AIIP Factor:	**1.5x**	**1.5x**	**1.5x**	**1.0x**	**1.0x**	
CCA 1.5x - (2021-2025)	9,366,575	9,366,575	9,366,575	9,366,575	9,366,575	46,832,873
CCA 1.5x (2021-2023); 1.0x (2024-2025) CCA	9,366,575	9,366,575	9,366,575	8,828,405	8,828,405	45,756,533
Adjustment to 2025 for 2024 UCC 1.0x vs 1.5x					(59,737)	(59,737)
CCA Difference	-	-	-	(538,170)	(478,433)	(1,016,603)
CCA Difference - Smoothed	(203,321)	(203,321)	(203,321)	(203,321)	(203,321)	(1,016,603)
CCA Difference	(203,321)	(203,321)	(203,321)	334,849	275,112	-
Annual CCA - Smoothed	9,163,254	9,163,254	9,163,254	9,163,254	9,163,254	45,816,270
CCA effect - 2021 Test Year	203,321					
Tax Rate	26.50%					
PILS Effect - 2021 Test Year	53,880					
PILS Effect - 2021 Test Year Grossed Up	73,306					
PILS Effect, 2021-2025, "Smoothed" CCA	269,400					
PILS Effect, 2021-2025, "Smoothed" CCA, Grossed Up	366,530					

APPENDIX E: 9-Staff-79 b)

Burlington Hydro Inc.
Impact of Bill 97 - Accelerated Rate Tax Depreciation
Per OEB Accounting Guidance Dated July 25, 2019

			Jan - Dec 2018					Jan - Dec 2019					Jan - Dec 2020				
	Rate	CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8		50,000		5,000	45,000	45,000			9,000	36,000	36,000			7,200	28,800
	30%	10		50,000		7,500	42,500	42,500			12,750	29,750	29,750			8,925	20,825
2018 - OLD	100%	12		245,000		122,500	122,500	122,500			122,500	-	-			-	-
	8%	47		7,255,045		290,202	6,964,843	6,964,843			557,187	6,407,656	6,407,656			512,612	5,895,043
	55%	50		70,000		19,250	50,750	50,750			27,913	22,838	22,838			12,561	10,277
		Total	-	7,670,045	-	444,452	7,225,593	7,225,593	-		729,350	6,496,243	6,496,243	-		541,298	5,954,945

								Jan - Dec 2019					Jan - Dec 2020				
		CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8							50,000		5,000	45,000	45,000			9,000	36,000
	30%	10							50,000		7,500	42,500	42,500			12,750	29,750
2019 - OLD	100%	12							245,000		122,500	122,500	122,500			122,500	-
	8%	47							7,255,045		290,202	6,964,843	6,964,843			557,187	6,407,656
	55%	50							70,000		19,250	50,750	50,750			27,913	22,838
		Total	-	-		-	-	-	7,670,045		444,452	7,225,593	7,225,593	-		729,350	6,496,243

													Jan - Dec 2020				
	Rate	CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8											-	50,000		5,000	45,000
	30%	10											-	50,000		7,500	42,500
2020 - OLD	100%	12											-	245,000		122,500	122,500
	8%	47											-	7,255,045		290,202	6,964,843
	55%	50											-	70,000		19,250	50,750
		Total	-	-	-	-	-	-	-		-	-	-	7,670,045		444,452	7,225,593

													Jan - Dec 2018 [Note 1]				
		CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8		50,000	41,191	13,238	36,762	36,762			7,352	29,409	29,409			5,882	23,528
	30%	10		50,000	4,245	8,773	41,227	41,227			12,368	28,859	28,859			8,658	20,201
2018 - AIIP	100%	12		245,000	75,426	160,213	84,787	84,787			84,787	-	-			-	-
	8%	47		7,255,045	3,643,072	581,648	6,673,397	6,673,397			533,872	6,139,526	6,139,526			491,162	5,648,364
	55%	50		70,000	8,621	23,992	46,008	46,008			25,305	20,704	20,704			11,387	9,317
		Total	-	7,670,045	3,772,554	787,863	6,882,182	6,882,182	-		663,684	6,218,498	6,218,498	-		517,089	5,701,409

								Jan - Dec 2019					Jan - Dec 2020				
		CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8							50,000	50,000	15,000	35,000	35,000			7,000	28,000
	30%	10							50,000	50,000	22,500	27,500	27,500			8,250	19,250
2019 -AIIP	100%	12							245,000	245,000	245,000	-	-			-	-
	8%	47							7,255,045	7,255,045	870,605	6,384,440	6,384,440			510,755	5,873,684
	55%	50							70,000	70,000	57,750	12,250	12,250			6,738	5,513
		Total	-	-		-	-	-	7,670,045	7,670,045	1,210,855	6,459,190	6,459,190	-		532,743	5,926,447

													Jan - Dec 2020				
		CCA Class	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending	Opening	Addition	AIIP	CCA	Ending
	20%	8												50,000	50,000	15,000	35,000
	30%	10												50,000	50,000	22,500	27,500
2020 - AIIP	100%	12												245,000	245,000	245,000	-
	8%	47												7,255,045	7,255,045	870,605	6,384,440
	55%	50												70,000	70,000	57,750	12,250
		Total	-	-		-	-	-	-		-	-	-	7,670,045	7,670,045	1,210,855	6,459,190

	Jan - Dec 2018	Jan - Dec 2019	Jan - Dec 2020	CCA Totals
SUM OF CCA - OLD RULES	444,452	1,173,802	1,715,100	3,333,353
SUM OF CCA - NEW RULES	787,863	1,874,539	2,260,687	4,923,090
INCREASE IN CCA	343,412	700,738	545,587	1,589,736
Tax Rate	26.50%	26.50%	26.50%	26.50%
TAX IMPACT	91,004	185,695	144,581	421,280

[Note 1] - 2018

	2018 Tax Return		
Class	Actual Additions	AIIP	% qualifying
8	341,856.00	281,626.00	82%
10	571,509.00	48,520.00	8%
12	259,014.00	79,740.00	31%
47	6,479,319.00	3,253,546.00	50%
50	268,845.00	33,110.00	12%

% Applied to Test Year Additions			
Class	Test Year Additions	Est. of Qualifying	% qualifying
8	50,000	41,191	82%
10	50,000	4,245	8%
12	245,000	75,426	31%
47	7,255,045	3,643,072	50%
50	70,000	8,621	12%

APPENDIX F: 9-Staff-79 c)

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
BURLINGTON HYDRO INC.	86829 1980 RC0001	2018-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes ☐ No ☒

	1 Class number * See note 1 **200**	Description	2 Undepreciated capital cost (UCC) at the beginning of the year **201**	3 Cost of acquisitions during the year (new property must be available for use) See note 2 **203**	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) See note 3 **225**	5 Adjustments and transfers See note 4 **205**	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 **221**	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 **222**	8 Proceeds of dispositions See note 7 **207**	For tax years ending before November 21, 2018: 50% rule (1/2 of net acquisitions) **211**
1.	1		58,126,371						0	
2.	1b		825,116	460,564	84,953				0	
3.	8		3,454,682	341,856	281,626				0	
4.	10		733,304	571,509	48,520				46,258	
5.	12		128,184	259,014	79,740				0	
6.	45		282						0	
7.	47	distribution equipment post Feb 22/05	40,733,619	6,479,319	3,253,546				0	
8.	50	Computers	49,160	268,845	33,110				0	
9.	95		139,159						0	
10.	14.1		2,207,160	1,000,000					0	
		Totals	106,397,037	9,381,107	3,781,495				46,258	

	1 Class number * See note 1 **200**	Des-crip-tion	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8	10 Proceeds of disposition available to reduce the UCC of AIIP (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for non-AIIP acquired during the year (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 **224**	14 CCA rate % See note 11 **212**	15 Recapture of CCA See note 12 **213**	16 Terminal loss See note 13 **215**	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 **217**	18 UCC at the end of the year (column 9 **minus** column 17) **220**
1.	1		58,126,371					4	0	0	2,325,055	55,801,316

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	1 Class number * See note 1 200	Des-crip-tion	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8	10 Proceeds of disposition available to reduce the UCC of AIIP (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for non-AIIP acquired during the year (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 212	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 217	18 UCC at the end of the year (column 9 **minus** column 17) 220
2.	1b		1,285,680		84,953	42,477	187,806	6	0	0	68,421	1,217,259
3.	8		3,796,538		281,626	140,813	30,115	20	0	0	781,447	3,015,091
4.	10		1,258,555		48,520	24,260	238,366	30	0	0	313,335	945,220
5.	12		387,198		79,740		89,637	100	0	0	297,561	89,637
6.	45		282					45	0	0	127	155
7.	47	distribu	47,212,938		3,253,546	1,626,773	1,612,887	8	0	0	3,778,146	43,434,792
8.	50	Compu	318,005		33,110	16,555	117,868	55	0	0	119,181	198,824
9.	95		139,159					0	0	0		139,159
10.	14.1		3,207,160				500,000	5	0	0	179,501	3,027,659
		Totals	115,731,886		3,781,495	1,850,878	2,776,679				7,862,774	107,869,112

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

COPY

APPENDIX G: 9-Staff-82 b)

KWh (Non-uplifted) Split by Type of Commodity

Rate Class

$\boxed{G10}$ -Not UL (Not Uplifted) Consumption Month	KWh Spot	KWh RPP-2 tiered	TOU	KWh with a Retailer
201901	604,104.67	2,777,465.64	.00	240,146.98
201902	543,881.41	2,592,548.79	.00	223,774.36
201903	537,846.69	2,538,764.31	.00	230,028.49
201904	636,370.96	1,997,758.11	.00	207,049.03
201905	620,617.27	1,818,158.03	.00	185,804.77
201906	478,444.29	1,772,964.46	.00	307,750.17
201907	569,036.67	2,245,411.09	.00	443,405.80
201908	619,349.27	2,116,849.21	.00	419,279.63
201909	545,765.53	1,710,836.80	.00	356,320.53
201910	504,688.32	1,840,616.77	.00	348,563.14
201911	537,534.67	2,142,956.26	.00	348,644.36
201912	956,681.82	2,448,795.07	.00	343,645.76

RPP kWh (non-uplifted) split by Tiers

2-T RPP NON-UPLIFTED G10 (Rate Class) Consumption Month	RPP1 (kWh)	RPP1$	RPP2 (kWh)	RPP2$
201901	2,183,826.21	168,154.66	593,639.44	52,833.92
201902	2,091,015.61	161,008.24	501,533.19	44,636.47
201903	2,181,347.97	167,963.81	357,416.37	31,810.04
201904	1,808,744.33	139,273.34	189,013.79	16,822.25
201905	1,578,306.82	121,529.66	239,851.27	21,346.75
201906	1,514,937.49	116,650.19	258,026.98	22,964.41
201907	1,764,520.65	135,868.10	480,890.51	42,799.25
201908	1,671,574.74	128,711.24	445,274.44	39,629.44
201909	1,487,119.81	114,508.25	223,717.01	19,910.81
201910	1,605,978.64	140,841.47	234,638.15	22,862.56
201911	1,857,100.37	206,395.54	285,855.98	34,680.92
201912	2,062,176.73	245,399.06	386,618.36	53,740.02

KWh (Non-uplifted) Split by Type of Commodity

Rate Class $\boxed{R35}$ -Not UL – Not Uplifted Consumption Month	Spot	KWh RPP-2 tiered	KWh TOU	KWh with a Retailer
201901	.00	33,888.19	43,888,753.58	635,760.87
201902	.00	32,266.44	38,734,469.48	562,151.06
201903	.00	18,956.25	38,920,080.99	561,213.70
201904	.00	28,545.35	34,081,526.41	486,536.65
201905	.00	22,643.09	34,739,326.12	477,447.31
201906	.00	20,208.90	42,281,672.05	541,054.82
201907	.00	30,981.13	59,467,460.93	748,394.46
201908	.00	39,316.01	53,993,984.09	668,245.49
201909	.00	71,436.25	40,497,144.68	488,889.17
201910	.00	81,688.79	35,919,747.04	448,886.55
201911	.00	83,611.93	37,162,098.75	468,095.02
201912	.00	64,529.47	42,089,313.42	521,667.49

KWh (Non-uplifted) Split by RPP Tiers

2-T RPP NON-UPLIFTED R35 (Rate Class) / Consumption Month	RPP1 (KWh)	RPP1$	RPP2 (KWh)	RPP2$
201901	16,575.90	1,276.37	17,675.29	1,573.09
201902	15,193.42	1,169.88	17,567.02	1,563.48
201903	11,514.35	886.67	8,381.33	745.94
201904	14,227.64	1,095.50	15,585.26	1,387.10
201905	10,180.53	783.94	13,355.63	1,188.64
201906	7,751.25	596.88	13,920.62	1,238.94
201907	11,697.14	900.87	20,989.99	1,868.11
201908	18,952.88	1,483.82	21,811.91	1,946.24
201909	38,878.62	3,007.09	33,668.95	3,004.03
201910	49,882.86	4,321.37	32,574.92	3,135.84
201911	55,937.60	6,155.57	28,108.89	3,451.15
201912	41,479.17	4,876.70	23,442.74	3,212.18

Kwh (NON-uplifted) Split by RPP TOU Buckets

RateClass

R35 - Not UL not uplifted Consumption Month	Kwh ON	$ON	Kwh MID	$MID	Kwh OFF	$OFF
201901	7,762,526.40	1,024,663.71	6,908,762.94	649,432.96	29,217,483.13	1,899,146.29
201902	7,018,865.98	926,504.60	6,225,803.99	585,239.12	25,489,812.48	1,656,852.67
201903	7,090,106.80	935,915.94	6,245,766.89	587,124.84	25,584,237.56	1,662,999.26
201904	5,911,982.58	782,241.12	5,455,027.55	512,813.30	22,714,635.37	1,476,493.47
201905	5,611,029.43	749,935.32	5,960,171.31	560,290.62	23,168,204.41	1,505,973.63
201906	7,396,452.27	991,130.60	7,357,044.93	691,570.36	27,528,179.86	1,789,336.77
201907	11,175,280.44	1,497,489.26	10,113,271.64	950,647.13	38,178,890.87	2,481,630.78
201908	10,216,020.17	1,368,957.81	9,313,567.92	875,486.52	34,464,420.23	2,240,203.98
201909	7,114,126.87	953,321.08	7,104,760.04	667,872.63	26,278,292.12	1,708,125.08
201910	5,993,306.37	896,306.25	6,280,040.18	645,098.77	23,646,518.68	1,706,765.40
201911	6,822,084.72	1,339,237.76	6,225,121.42	834,766.13	24,115,091.56	2,294,684.80
201912	7,325,446.14	1,523,716.22	6,511,676.48	937,709.70	28,252,321.27	2,853,498.50

APPENDIX H: 9-Staff-82 b)

Independent Electricity System Operator
PHYSICAL INVOICE

Independent Electricity System Operator
Station A, Box 4474
Toronto, ON
M5W 4E5

HST: 870513959RT0002
Issue / Re-Issue Date: **15-JAN-2020**

BURLINGTON HYDRO INC.
1340 Brant Street
Burlington, ON L7R 3Z7
Canada

Invoice: PI00029051
Invoice Date: 15-JAN-2020
MP ID: 102298
MP GST/HST: 868291980

Please send payment by WIRE or EFT to:

Bank Name: **TD Bank**
Bank ID Number: **0004**
Bank Account Number: **0690-0458762**

Bank Acc Type: **Settlement Clearing**
Bank Transit Number: **10202**

For all inquiries contact:
IESO Account Representative
Tel: 905-403-6900
Toll Free: 1-888-448-7777

Comments:

Charges for settlement statements issued: From 01-DEC-2019 To 31-DEC-2019

Charge Type	Description	Amount
101	NET ENERGY MARKET SETTLEMENT FOR NON-DISPATCHABLE LOAD	$2,922,687.48
102	TR CLEARING ACCOUNT CREDIT	$0.15
142	REGULATED PRICE PLAN SETTLEMENT AMOUNT	$1,160,592.31
147	CLASS A GLOBAL ADJUSTMENT SETTLEMENT AMOUNT	$1,127,641.68
148	CLASS B GLOBAL ADJUSTMENT SETTLEMENT AMOUNT	$11,076,999.50
150	NET ENERGY MARKET SETTLEMENT UPLIFT	$67,223.48
155	CONGESTION MANAGEMENT SETTLEMENT UPLIFT	$54,387.80
169	STATION SERVICE REIMBURSEMENT DEBIT	$2,371.03
183	GENERATION COST GUARANTEE RECOVERY DEBIT	$34,081.19
186	INTERTIE FAILURE CHARGE REBATE	($640.01)
250	10-MINUTE SPINNING MARKET RESERVE HOURLY UPLIFT	$9,507.26
252	10-MINUTE NON-SPINNING MARKET RESERVE HOURLY UPLIFT	$14,872.96
254	30-MINUTE OPERATING RESERVE MARKET HOURLY UPLIFT	$5,242.01
450	BLACK START CAPABILITY SETTLEMENT DEBIT	$1,419.60
451	HOURLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	$16,154.00

452	MONTHLY REACTIVE SUPPORT AND VOLTAGE CONTROL SETTLEMENT DEBIT	$855.35
454	REGULATION SERVICE SETTLEMENT DEBIT	$51,092.57
650	NETWORK SERVICE CHARGE	$917,093.50
651	LINE CONNECTION SERVICE CHARGE	$241,528.32
652	TRANSFORMATION CONNECTION SERVICE CHARGE	$578,661.60
753	RURAL RATE SETTLEMENT CHARGE	$66,511.40
900	GST/HST CREDIT	($326,520.11)
950	GST/HST DEBIT	$2,762,447.07
1143	ONTARIO FAIR HYDRO PLAN ELIGIBLE NON-RPP CONSUMER DISCOUNT SETTLEMENT AMOUNT	$372,620.46
1350	CAPACITY BASED RECOVERY AMOUNT FOR CLASS A LOADS	$3,577.63
1351	CAPACITY BASED RECOVERY AMOUNT FOR CLASS B LOADS	$35,131.11
1412	FEED-IN TARIFF PROGRAM SETTLEMENT AMOUNT	($185,601.16)
1416	CONSERVATION AND DEMAND MANAGEMENT-COMPENSATION SETTLEMENT CREDIT	($27,982.05)
1420	ONTARIO ELECTRICITY SUPPORT PROGRAM SETTLEMENT AMOUNT	($83,015.83)
1463	RENEWABLE GENERATION CONNECTION - MONTHLY COMPENSATION AMOUNT SETTLEMENT DEBIT	$2,973.08
1550	DAY-AHEAD PRODUCTION COST GUARANTEE RECOVERY DEBIT	$5,822.40
1650	FORECASTING SERVICE BALANCING AMOUNT	$522.33
9980	SMART METERING CHARGE	$38,164.35
9982	ONTARIO REBATE FOR ELECTRICITY CONSUMERS (8% PROVINCIAL REBATE) SETTLEMENT AMOUNT	($161,715.19)
9983	ONTARIO ELECTRICITY REBATE SETTLEMENT AMOUNT	($2,987,607.18)
9990	IESO ADMINISTRATION CHARGE	$144,385.23
	PHYSICAL MARKET INVOICE PREPAYMENT	($6,000,000.00)

Invoice Total:	$CAD	11,941,485.32

Payment Due Date 17-JAN-2020

This invoice also constitutes a debit/credit note for GST/HST purposes

Burlington Hydro Inc
IESO Invoice CT148 - GA Booked to 1588 and 1589
For the month of December 2019
Response to Staff IR-82 b)

										DECEMBER 2019 - UPDATED (FIRST TRUE UP)			
	Source	**kWh**						**Cost of Power - Dollars**					
Energy Purchased from IESO (AQEW)	IESO power bill	133,022,800						RPP	$ 1,557,749			**Other Data:**	
Add: Generation	IESO Form 1598	384,696						Non RPP	$ 1,371,558	**CT148 - Dec.2019**		GA 1st Est.	0.08569
Total available energy		133,407,496					C	**RPP GA**	**$ 6,608,738**	**$ 11,077,000**		GA 2nd Est.	0.09066
			D				E	**Non RPP GA**	**$ 4,468,262**			GA Actual	0.09321
Non - RPP Component			**Non RPP Split b/w Class A & B**				**Booked to 1589**	Non RPP GA " A"	$ 1,127,642			GA Invoice Rate	0.0932132
Usage of BHI Customers on spot	BL 8587_SS	50,860,063	14,572,349	Class A from IESO power bill		**B**	**E**	Generation	$ -				
Usage by customers with Retailers	BL 8585_CS	11,648,243	**47,935,957**	**Class B - Balance kwh**		**$ 0.0932132**	**$ 4,468,262**	1598 Dec estimate	$ 1,145,543				
		62,508,306	62,508,306				**(D * B = E)**	1598 Dec updated	$ (199,943)				
RPP Portion		**A**	**B**	**C**				1598 Oct trueup	$ (89,502)	GL Details			
Energy eligible for statutory price		**70,899,190**	**$ 0.0932132**	**$ 6,608,738**	**Booked to 1588**			1598 Nov trueup	$ 21,359	10,116,112	Energy		
				(A * B = C)				1598 Dec trueup	$ (142,140)	5,753,154	GA		
								(incl.Jan-Nov final trup)	$ 15,869,266	15,869,266	Total		
IESO Energy rate per kWh	IESO Invoice WAP	$ 0.0219713											
Estimated Global Adjustment per kWh	**IESO Invoice GA**	**$ 0.0932132**											
Statutory Price of Energy per kWh		$ 0.1151845											
RPP GA Portion (based on RPP kWh)		**$ 6,608,737.52**											