Burlington Hydro Inc.

2021 Cost of Service Application
EB-2020-0007

October 30, 2020

EXHIBIT 1

ADMINISTRATIVE DOCUMENTS

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EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1.0 INTRODUCTION

Burlington Hydro Inc.'s ("BHI's") 2021 Cost of Service Application (EB-2020-0007) (the "Application") describes how BHI will develop, manage, operate and maintain its distribution system to provide safe, secure, reliable, efficient, and cost-effective service to its customers. The period for this Application generally covers eight years with a seven-year historical period beginning with 2014 and ending with the 2020 Bridge Year; and a one-year forecast period - the 2021 Test Year. The Distribution System Plan ("DSP") covers twelve years, including a five-year forecast period beginning with the 2021 Test Year and ending in 2025. BHI's last Cost of Service application and DSP was filed October 1, 2013 for rates effective May 1, 2014.

This Application contains nine exhibits, including this Exhibit 1, as follows:

- Exhibit 1 - Administrative Documents
- Exhibit 2 - Rate Base, including the DSP
- Exhibit 3 - Operating Revenue
- Exhibit 4 - Operating Expenses
- Exhibit 5 - Cost of Capital and Capital Structure
- Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts

BHI has prepared this Application in accordance with the following:

- the Ontario Energy Board's ("OEB's") *Chapter 2 Cost of Service Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications* issued May 14, 2020 (the "Chapter 2 Filing Requirements");
- the OEB's *Chapter 5 Consolidated Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications* issued May 14, 2020 (the "Chapter 5 Filing Requirements"); and

- the OEB's *Handbook for Utility Rate Applications* issued October 13, 2016.

BHI has not deviated from these filing requirements and provides a checklist of the filing requirements as Appendix A, which identifies the specific reference in the Application where relevant information is provided.

This Exhibit 1 provides information relating to the administration of this Application and contains eleven sections including this introductory **Section 1.0**. **Section 1.1** provides a Table of Contents listing the major sections and subsections of the Application. **Section 1.2** provides an Executive Summary to identify key elements of BHI's proposals and the Business Plan underpinning this Application. **Section 1.3** provides a complete summary of the Application to be posted as a stand-alone document on the OEB's website for review by the general public, and be made available to BHI's customers. **Section 1.4** includes administrative information related to this Application. **Section 1.5** includes an overview of BHI's distribution system. **Section 1.6** provides a summary of the Application including proposed changes. **Section 1.7** discusses how BHI informed its customers of the proposals being considered for inclusion in the Application, and the value of those proposals to customers. **Section 1.8** discusses BHI's performance measurement and improvement targets. **Section 1.9** provides BHI's financial information. **Section 1.10** discusses distributor consolidation. This Exhibit is organized using the same section headings indicated in the Chapter 2 Filing Requirements.

1.1 APPLICATION TABLE OF CONTENTS

BHI provides a Table of Contents listing the major sections and subsections of its Application below.

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1.2 EXECUTIVE SUMMARY AND BUSINESS PLAN

1.2.1 Introduction

BHI provides a summary of the key elements of its Application in this Section 1.2. These include the business, capital and operating plans that underpin the Application and the corresponding funding that is required to develop, manage, operate, and maintain its distribution system to provide safe, secure, reliable, efficient, and cost-effective service to its customers. BHI's plans are an outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. BHI developed its plans to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

1.2.2 BHI's Goals

BHI's specific goals associated with this Application are as follows:

- Maintain reliability, safety and service quality;
- Pace its level of investments to minimize rate impacts;
- Address key pressures to the system, including:
    - Infrastructure at the end of its useful life; and
    - The effects of severe weather events;
- Make prudent investments in critical business systems to enhance service offerings and avoid increases in operating costs; and
- Maintain a focus on continuous improvement, efficiency, and productivity.

BHI provides further details in its Application Summary in Section 1.6 of this Exhibit 1 and provides a summary if its realized efficiencies and improvements in Section 1.2.8 below.

1.2.3 About BHI

BHI is a municipally owned local distribution company ("LDC") serving the City of Burlington ("the City"), with a total licensed service area of 188 square kilometres and a customer base of approximately 68,000 customers (consisting of Residential, Commercial, Street Light, and Unmetered Scattered Load customers). BHI delivers electricity into the community through a network of 1,600 kilometres of medium-voltage distribution lines and 32 substations. The company celebrated its 75th Anniversary in 2020.

BHI is one of two subsidiary companies, in addition to an unregulated company - Burlington Electricity Services Inc. ("BESI") - wholly owned by the City of Burlington through a holding company. In 2019, the governance model for this holding company - Burlington Hydro Electric Inc. ("BHEI") - was restructured and renamed Burlington Enterprises Corporation ("BEC"), to better align with the governance structure supported and preferred by the Ontario Energy Board ("OEB"). This change is discussed in further detail in Section 1.4.15 of this Exhibit 1.

BHI strives to exemplify excellence in every aspect of its business. From the exacting work of its engineers and the professionalism of its customer service representatives, to its resilient operations crews and all those in-between, BHI works together to deliver value at every level of the organization.

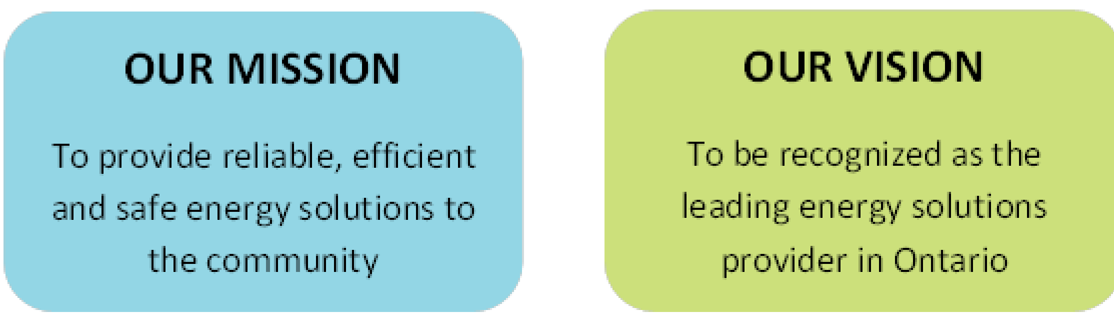
BHI has won several awards since its last rebasing application as follows:

- 2015 EDA Communications Excellence Award – for BHI's "'Shine"' and "Shine Inside" initiatives - BHI's intranet;
- 2015 Burlington Chamber of Commerce Business Excellence Award - for a Large Service Company;
- 2016 Hamilton-Niagara Regional Top Employer – regional winner from the Canada's Top 100 Employers;
- 2016 EDA/ESA Public Electrical Safety Award – for 'Power to be Safe' campaign;
- 2016 Canada's Safest Employer, Silver – awarded by Canadian Occupational Safety;
- 2017 EDA Public Relations Excellence Award – for Plant-a-Tree in a Community Park campaign to encourage paperless billing registrations;
- 2017 EDA/IESO Conservation Leadership Excellence Award – for the 'Power to Conserve' campaign;
- 2018 Canada's Safest Employer, Silver – awarded by Canadian Occupational Safety;
- 2019 Hamilton-Niagara Regional Top Employer – regional winner from the Canada's Top 100 Employers;

- 2019 Canada's Safest Employer, Silver – awarded by Canadian Occupational Safety;
- 2020 Hamilton-Niagara Regional Top Employer – regional winner from the Canada's Top 100 Employers; and
- 2020 Canada's Safest Utilities and Electrical Employer, Gold – awarded by MSA (tied with Waterloo North Hydro).

1.2.4 BHI's Business Plan

In accordance with the OEB's *Handbook for Utility Rate Applications*[1], BHI has prepared a formal Business Plan that outlines BHI's overall strategy and goals. The Business Plan was approved by BHI's Board of Directors on September 14, 2020 and is included in this Exhibit 1 as Appendix B.



BHI's mission is to provide reliable, efficient and safe energy solutions to the community.

BHI's vision is to be recognized as the leading energy solutions provider in Ontario by:

1. Ensuring a safe, reliable distribution service;
2. Delivering electricity at reasonable distribution rates;
3. Investing in new technology that could help reduce future distribution electricity costs;
4. Replacing aging infrastructure that is beyond its useful life;
5. Finding efficiencies and ways to find cost savings;

[1] Ontario Energy Board, *Handbook for Utility Rate Applications*, October 13, 2016

6. Upgrading the distribution system to better respond to and withstand the impact of adverse weather;
7. Providing quality customer service and enhanced communications; and,
8. Providing customers with conservation information and education as it relates to public electrical and powerline safety.

BHI's core values are caring for people and community, and caring about stewardship and sustainability – all with a commitment to continuous improvement in everything that it does.

Burlington Hydro Cares for People

We interact with customers, employees, the public, and our business partners with integrity and respect, and at all times act in a responsible and professional manner.

Burlington Hydro Cares for the Community

We take pride in making significant contributions to our community by helping to implement and contribute to the City's 'Climate Action Plan' and 'Climate Change Adaptation Plan', supporting local business development activities, and delivering important safety programs to our schools, among others.

Burlington Hydro Cares about Stewardship

We value the long term health and sustainability of Burlington Hydro and will assure availability of a future electricity supply that meets customer needs and growth. We value the community we serve and the environment in which we operate, managing environmental risks to eliminate or minimize adverse impacts associated with our businesses.

Burlington Hydro Cares about Performance

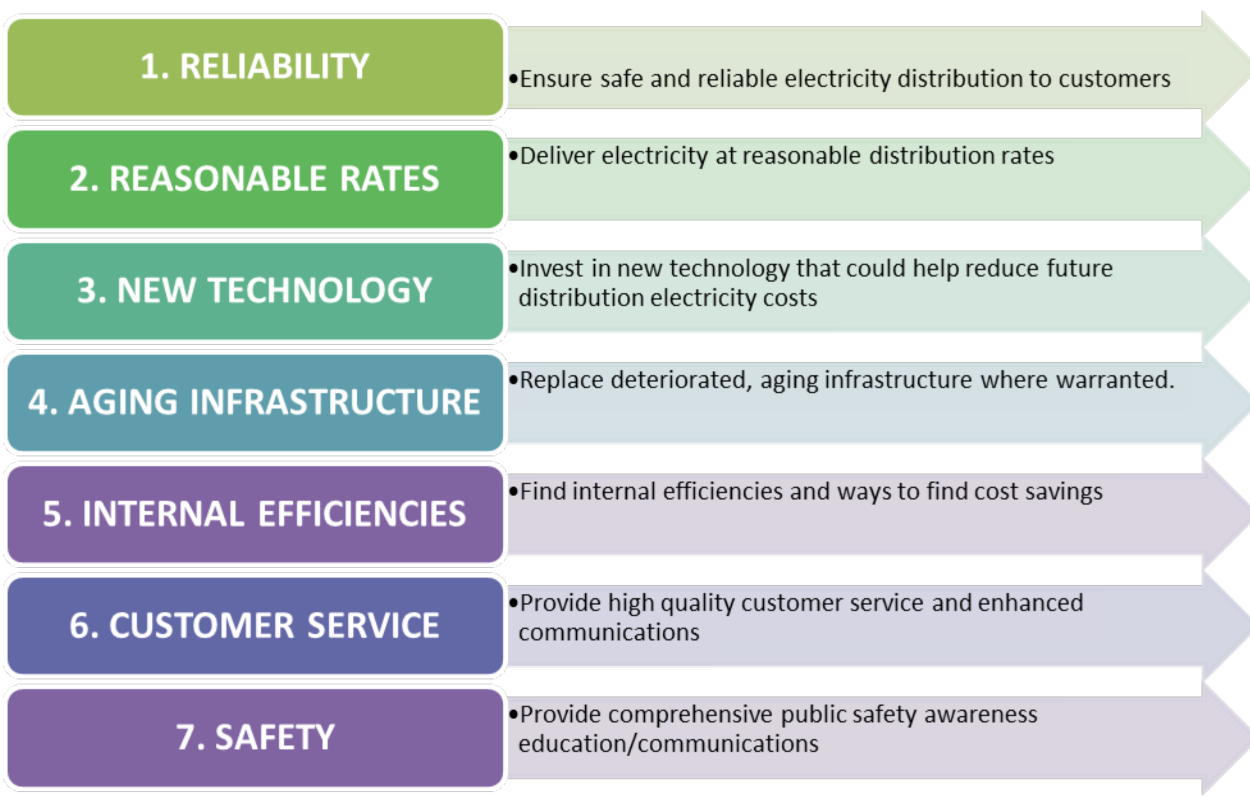
We value a fully integrated business model. We deliver superior products to our customers in a safe and efficient manner, striving for excellence and continuous improvement in all aspects of our business.

Burlington Hydro Cares about Shareholder Value

We create sustainable value for our shareholder by understanding and addressing customer needs, focusing on and promoting core business strengths, and pursuing appropriate business opportunities.

BHI's plans are developed to ensure that it continues to provide reliable, efficient and safe energy solutions to the community by achieving its seven core strategic objectives as identified in Figure 1 below. Its plans were informed by a number of factors, including operational needs; (e.g. requirements relating to capital investment; operations and maintenance; and staffing); legislative and regulatory obligations; and ongoing engagement with customers.

Figure 1 – BHI's Strategic Objectives



1.2.5 Alignment with the Renewed Regulatory Framework

BHI's Mission, Values and Strategic Objectives align with the OEB's Renewed Regulatory Framework and the achievement of performance outcomes as documented in the OEB's Report of the Board - *Renewed Regulatory Framework for Electricity Distributors*: *A Performance Based Approach*[2] (the "RRFE Report"). The four RRFE outcomes are as follows:

- **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
- **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
- **Financial Performance**: financial viability is maintained.

Table 1 below illustrates the alignment between BHI's strategic objectives and the four categories of performance outcomes under the RRFE.

Table 1 – Alignment of Strategic Objectives to RRFE

RRFE Performance Outcomes	Strategic Principle	Strategic Objective
Customer Focus	Customer Focus	Provide high quality customer service and enhanced communications
		Deliver electricity at reasonable distribution rates
Operational Effectiveness	Operational Effectiveness	Replace deteriorated, aging infrastructure where warranted
		Ensure safe and reliable electricity distribution to customers
		Invest in new technology that could help reduce future distribution electricity costs
Public Policy Responsiveness	Public Policy Responsiveness	Provide comprehensive public safety awareness education/communications
Financial Performance	Strong and Sustainable Financial Performance	Find internal efficiencies and ways to find cost savings

[2] Ontario Energy Board, Report of the Board: *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012

BHI's asset management objectives also incorporate the OEB's RRFE outcomes. In particular:

- For Operational Effectiveness, the asset management objectives aim to: (i) construct, maintain and operate all assets in a safe manner and (ii) monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery;
- For Customer Focus, the asset management objectives are designed to ensure that asset management plans align with customer expectations;
- For Financial Performance, the asset management objectives are aimed to manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance;
- For Public Policy Responsiveness, the asset management objectives are designed to ensure that BHI is in compliance with all legislation and regulations; and that environmental impacts are considered in the design and management of the distribution system.

BHI's asset management objectives have been developed to align with its Core Values, Vision and Mission to encompass strategic goals and objectives that are aimed to (i) optimize operations and lifecycle management and related processes in relation to asset renewal in order to maintain reliability and customer service levels; and (ii) proactively enhance customer engagement and levels of service.

Table 2 below illustrates how BHI's asset management objectives align with the RRFE Performance Outcomes.

Table 2 – Asset Management Objectives

RRFE Performance Outcome(s)	Asset Management Objective	Definition
Customer Focus	Customer Preference	Ensure the asset management plans are aligned with customer expectations and needs.
Operational Effectiveness	Reliability	Ensure the asset management system provides a sustainable and reliable service to the customers.
	Asset Performance	Ensure the asset management plans reduce poor performing assets and provide the opportunity to modernize the system.
	Operational Efficiency	Ensure the asset management plans provide sustainable cost savings and generate new opportunities for reducing the life cycle costs of operating assets.
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.
	Environmental Protection	Ensure the impacts of capital investments on sensitive environmental features are minimized.
	Regulatory Compliance	Ensure the asset management plans are in regulatory compliance and legal obligations are met.
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.
	Risk Management	Ensure BHI effectively manages risk – financial, operational, cyber security, regulatory, obsolescence.

1.2.6 Key Elements of BHI's Proposals in this Application

BHI's Application was developed to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

In the sections below, BHI provides a high-level overview of the key elements driving the proposals in this Application, including customer needs and preferences; and a description of major system challenges.

1.2.6.1 Customer Preferences and Expectations

BHI engages with its customers on an ongoing basis and through a variety of channels such as an annual customer satisfaction survey for residential and small business customers, large customer satisfaction surveys, daily customer service interactions, community outreach, and through social media platforms such as Twitter. In addition, BHI conducted an extensive customer engagement exercise as part of this Application consisting of two phases, including soliciting feedback from customers on major investments proposed for 2021 to 2025.

BHI's customers indicated that i) reasonable distribution rates; ii) ensuring reliable electricity service; and iii) finding internal efficiencies and ways to find cost savings were their top three priorities. Throughout the engagement, customers consistently noted that they would be supportive of proactive, incremental investments for system renewal and other investments that provide benefit to customers into the future. The majority of customers indicated that BHI has found the right balance between the level of investment proposed in the draft plan and the associated rate impacts presented.

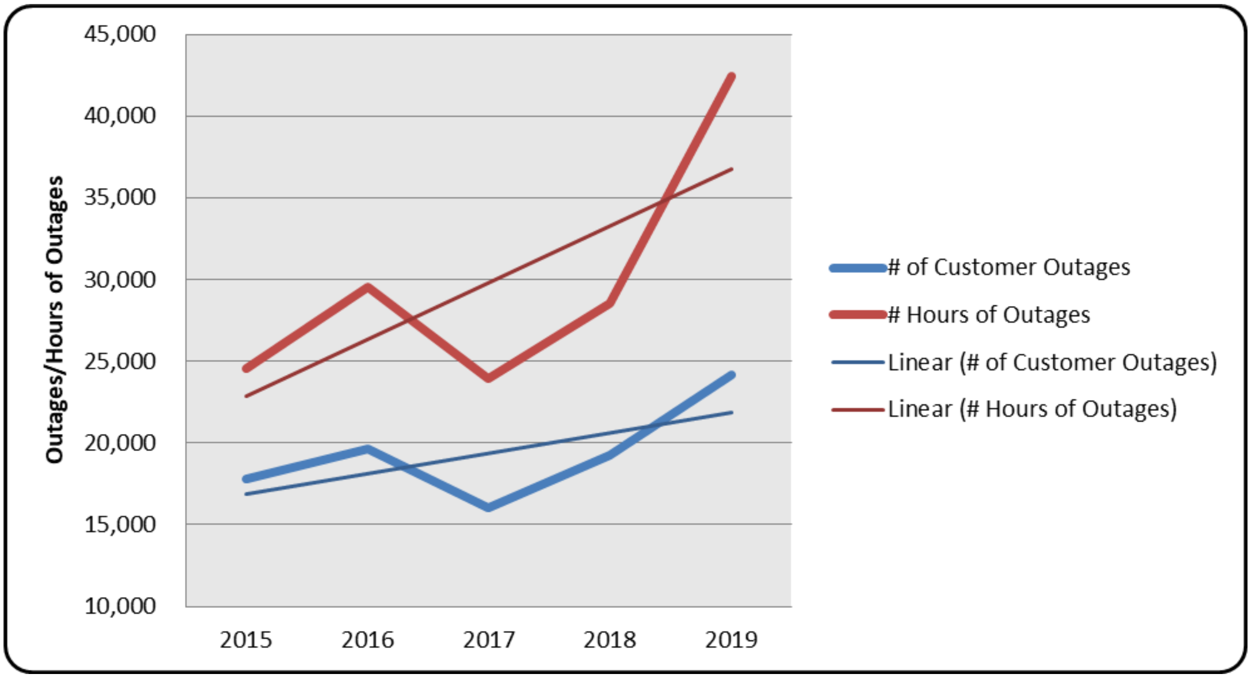
As such, BHI has developed its plans to pace investments to balance the competing priorities of minimizing rate impacts; maintaining safety and reliability through the replacement of infrastructure at the end of its useful life; and maintaining a focus on continuous improvement, efficiency, and productivity.

BHI provides further details on its customer engagement activities in Section 1.7 of this Exhibit 1, and in Section 5.4(a) of the DSP.

1.2.6.2 Deteriorating Condition of Distribution Infrastructure

BHI's distribution system faces a number of significant and evolving challenges that drive the need for the proposed level of investment. As supported by BHI's Asset Condition Assessment ("ACA"), a large percentage (26%) of BHI's asset base is in Very Poor, Poor or Fair condition, indicating at a minimum that replacement may be required depending on the asset's criticality. Furthermore, assets in Fair condition will continue to deteriorate into Poor or Very Poor condition over the Application horizon. BHI is proposing a proactive replacement program in order to address assets currently in Poor or Very Poor condition, while mitigating the risk of an increasing renewal backlog from the group of assets currently in Fair condition. An increase in the backlog of assets past useful life would result in deterioration in reliability, safety, and other outcomes driven by asset failure. Defective equipment is the largest contributor to the frequency (33 percent), and duration (34 percent) of outages. Outages due to defective equipment are trending unfavorably as indicated in Figure 2 below.

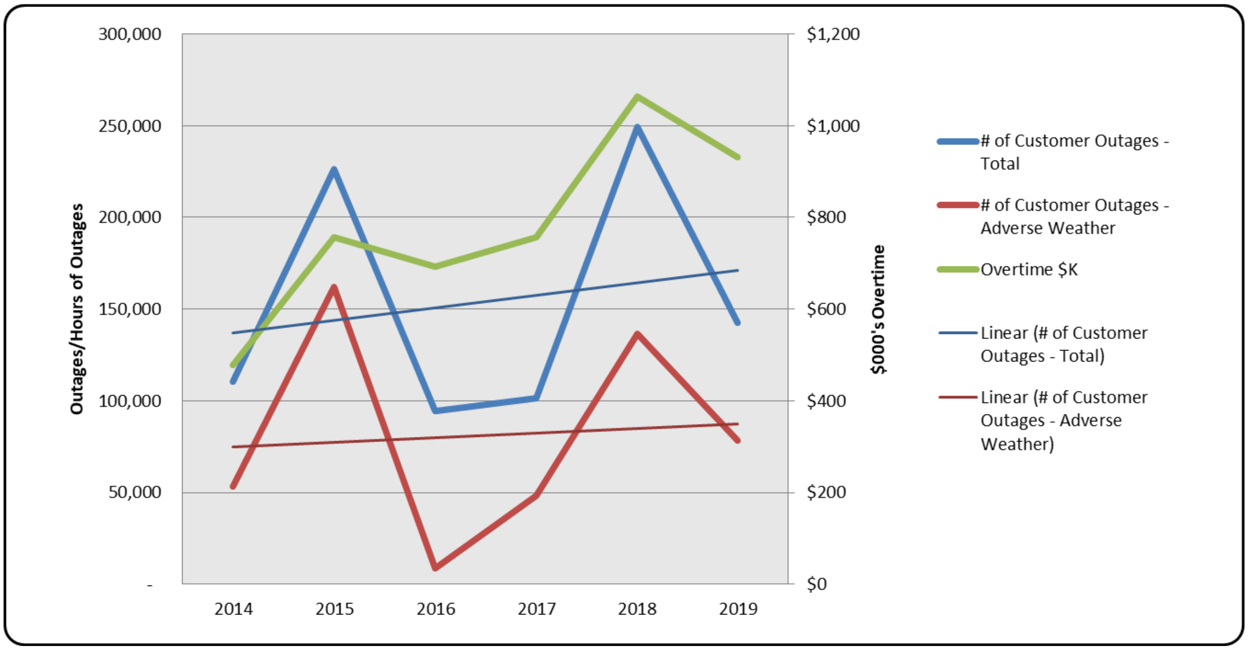
Figure 2 – Outages due to Defective Equipment



1.2.6.3 Adverse Weather Events

In addition to reliability challenges posed by a backlog of deteriorating and obsolete equipment, increasingly frequent adverse weather events have put additional reliability pressures on BHI's distribution system. Recent adverse weather events, especially in 2018, have significantly affected BHI's customers. These circumstances drive the need for investments to facilitate and improve system resiliency and BHI's ability to respond to adverse weather events. Proposed investments in the renewal of legacy assets, through reinforcement and replacement, will contribute to system hardening by improving asset health and introducing updated equipment design and construction standards that are better suited to the changing operating environment. In addition to affecting system reliability these outages negatively impact operating expenditures through an increased incidence of overtime as identified in Figure 3 below.

Figure 3 – Total Outages and Outages due to Adverse Weather



1.2.6.4 City Growth and Capacity Constraints

BHI has an obligation to ensure that its distribution system has sufficient capacity to connect new customers and to alleviate capacity constraints. BHI's investment needs in this respect are primarily driven by the pace and extent of multi-unit residential and new subdivisions development in its service territory. This growth is pushing certain distribution equipment to capacity. Infrastructure renewal and upgrades are required to support that growth while maintaining reliability and safety outcomes. Proposed investments in the System Access and System Service categories are driven by the projected level of demand, informed in part by planning documents such as the Halton Region Official Plan, included as Appendix 2 of the DSP, and the Region of Halton's ("the Region") Growth Plan for the Greater Golden Horseshoe, included as Appendix 3 of the DSP.

BHI has been facing a large number of third-party infrastructure renewal and expansion projects that require the utility to relocate its existing infrastructure. BHI is obligated by the *Public Service Works on Highways Act*[3] to accommodate these third-party requests in a fair and reasonable

[3] Public Service Works on Highways Act, R.S.O. 1990, c. P.49

manner. For the 2021-2025 period, BHI is expecting greater needs in this area due to a larger number of committed relocation and expansion projects by Metrolinx, the Region, the City and the Ministry of Transportation.

1.2.6.5 Business Operations Continuity

BHI must also continue to maintain and enhance its non-distribution system assets to allow the utility to efficiently and effectively execute the proposed capital program, maintenance activities and be responsive to customer needs and requests.

In addition to fleet, facilities and IT asset renewal investments, BHI has identified a one-time capital expenditure for a new Enterprise Resource Planning ("ERP") system that is required during the forecast period and for which it is requesting approval through an Advanced Capital Module ("ACM") in Section 2.2.3 of Exhibit 2. BHI's current ERP system is more than 20 years old and is approaching obsolescence due to the lack of vendor support and other functional deficiencies. To meet evolving regulatory, customer and operational demands, BHI is proposing to replace the existing ERP system in 2023 with a new, fully supported system, which would deliver new functionality and benefits.

1.2.6.6 Operations, Maintenance and Administration

The environment in which BHI operates had undergone significant change since 2014, which has had an impact on the costs to operate and maintain its distribution system. In addition to the challenges posed by infrastructure at the end of its useful life, defective equipment and adverse weather, there have been changes in BHI's workforce and the job market; operational changes; technological advancements; and regulatory and policy changes which have impacted BHI.

Workforce and Job Market Changes

During the period between 2014 and 2019, BHI experienced a workforce turnover rate of 49 percent; consequently, approximately 50 percent of its current workforce has less than five year's tenure/experience with the organization. Workforce and succession planning remain critical over the next five years as BHI expects to experience turnover of 20 percent of its workforce between 2021 and 2025. This is solely due to anticipated retirements; 25 percent turnover is expected between 2020 and 2025. Matching the resource capability with the work demands in the electrical distribution sector requires both short and longer-term planning. Numerous contributing factors are impacting BHI's workforce planning including:

- Managing the effects of its aging workforce including significant turnover in 2015 to 2021 primarily due to retirements;
- Dealing with a shortage of skilled labour in the electrical industry;
- Leveraging technological advancements and ensuring BHI is capable of delivering on customer expectations while at the same time competing for new emerging skills; and
- Increased work demands, due in part to the requirement to replace distribution infrastructure beyond its useful life.

The high turnover experienced by BHI between 2015 to 2019 - in addition to the difficulty in recruiting for positions which are in short supply - has been exacerbated by the number of vacant positions at BHI year-over-year since 2014.

BHI operates in an extremely competitive market in which there are challenges recruiting for certain positions, particularly power system operators, engineers and electricians; and Information and Technology ("IT") occupations. A shortage of fully competent, proficient employees in the marketplace to fill vacancies requires BHI to advance hire a higher percentage of apprentices who require four to seven years of training to reach full proficiency.

<u>Operations and Maintenance Changes</u>

BHI has reflected current market costs for vegetation management in this Application. Vegetation-related power interruptions have a significant impact on system reliability and are second only to defective equipment as the leading cause of customer interruptions. During extreme weather events, the distribution system is particularly vulnerable to tree contacts and costly tree damage. Incremental costs have been partially offset by a reduction in the costs associated with the provision of locates. BHI switched locate providers in 2018 and negotiated a reduction in the hourly charge for locates, which resulted in a reduction in total cost.

<u>Technological Advancements</u>

BHI must strategically navigate the challenging and rapid technology changes within the industry and the IT infrastructure support arena, including the ever advancing cyber security threat landscape. Changes since 2014 include moving to an outsourced model for cyber security monitoring; leveraging cloud technologies for disaster recovery; implementation of an Electronic Document Records Management System; and an increase in security and management of customer facing applications on a 24X7 basis.

For BHI, these challenges demand strategic outsourcing of selected IT services in balance with the realignment of internal IT resource skillsets in order to effectively manage costs and meet IT scheduled commitments.

Regulatory and Policy Changes

There have been numerous changes to regulatory requirements and public policy as identified below, some of which have put upward pressure on costs.

- Transition to IFRS (2015)
- Implementation of the Ontario Electricity Support Program (“OESP”) (2016)
- Revision to the OEB Cost Assessment Model (2016)
- Transition to Monthly Billing (2017)
- Implementation of the Fair Hydro Plan Act (2017)
- Introduction of the Winter Disconnection Moratorium (2017)
- Implementation of the OEB Cyber Security Framework (2018)
- The cancellation and centralization of Conservation and Demand Management (“CDM”) (2019 & 2020)
- Implementation of the Ontario Rebate for Electricity Consumers Act (“OREC”) (2019)
- Implementation of changes to Customer Service Rules (2019 & 2020)
- Elimination of the Collection of Account Charge (2019)
- Installation of Metering Inside the Settlement Timeframe (MIST) meters for GS>50kW customers (2020)
- Implementation of the OEB’s standardized accounting process for RPP settlement (2019)
- Implementation of COVID-19 Billing Changes (2020)
- Implementation of Time of Use Opt-Out (2020)

- Implementation of changes to engineering, construction and purchasing standards required under O.Reg 22/04 Electrical Distribution Safety
- Implementation of COVID-19 safety measures
- Implementation of engineering solutions as identified in Electrical Safety Authority ("ESA") audits year over year.

Incremental costs and/or a reduction in revenue were associated with some of these changes, which have been recorded in a Deferral and Variance Account ("DVA") since inception until the present. These costs/lost revenues are now factored into BHI's revenue requirement in this Application and are contributing to BHI's proposed rate increase. These specific policy changes are: the Revision to the OEB Cost Assessment Model[4], the Transition to Monthly Billing[5], and the Elimination of the Collection of Account charge[6].

1.2.6.7 Deferral and Variance Accounts

BHI typically disposes of its Group 1 Deferral and Variance Accounts ("DVAs") on an annual basis in its Incentive Rate Mechanism ("IRM") applications. Group 1 DVAs track the difference between revenues collected from customers and costs paid by BHI for the cost of power. Group 2 DVAs are typically associated with policy changes; and track costs and revenues incremental to that which was approved in rates. They are subject to a prudence review and are generally disposed of in a rebasing application. BHI has been accumulating balances in its Group 2 accounts over multiple years, some as far back as 2014. Consequently, the balance in BHI's Group 2 accounts for which it is requesting disposition is $2,708,451. In addition, the balance in BHI's Group 1 accounts for which it is requesting disposition is $2,433,347, primarily driven by a proposed recovery from customers related to the Global Adjustment ("GA") in the amount of $1,945,901. BHI's GA costs charged by the Independent Electricity System Operator ("IESO") in 2019 were higher than that collected from customers. (BHI bills customers on the IESO's first estimate for GA and pays the IESO actual GA – in 2019 the cost paid to the IESO for GA exceeded the amount that BHI collected from customers).

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[4] OEB Letter re *Revisions to the Ontario Energy Board Cost Assessment Model*, February 9, 2016
[5] p 15, Decision and Rate Order EB-2016-0384, April 20, 2017
[6] EB-2019-0179 Decision and Order, September 19, 2019

The magnitude of these proposed dispositions - in conjunction with a net refund to customers in 2020 for commodity pass through accounts - results in a significant bill impact to BHI customers. The OEB has stated in its *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* that "*the default disposition period used to clear the Account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate*."[7] As such, BHI is proposing to dispose of its Group 1 and Group 2 DVAs over two years, in order to mitigate the bill impact of this DVA disposition. Disposition of BHI's DVAs is discussed in further detail in Section 1.6 H of this Exhibit 1.

In addition to some of the challenges mentioned above, the COVID-19 Pandemic has had a significant impact to BHI's operations and load as identified in Section 1.2.7 below.

1.2.7 COVID-19 Pandemic

1.2.7.1 Background

The COVID-19 pandemic ("COVID-19"), is an ongoing pandemic caused by severe acute respiratory syndrome coronavirus 2 ["SARS-CoV-2"]. This infectious disease was first identified in December 2019 in Wuhan, China. The World Health Organization declared the outbreak a Public Health Emergency of International Concern on January 30, 2020 and a pandemic on March 11, 2020. On March 17, 2020, the Government of Ontario declared a state of emergency under the Emergency Management and Civil Protection Act ("EMCPA") to help fight the spread of COVID-19. The City declared a state of emergency on March 21.

The state of emergency announced by the Government of Ontario allowed it to create and enforce emergency orders. It ordered non-essential workplaces to close, restricted retirement and long-term care home employees from working in more than one facility and prohibited events and gatherings. These restrictions remained in place until May 4, 2020, negatively impacting the economy and significantly impacting BHI's customers. A high proportion of residential customers were at home during the day as they were required to work from home; were laid off; or had been terminated. Commercial customers were required to shut-down or

[7] EB-2008-0046, July 31, 2009, p 24

experienced reduced operating hours. The impact on BHI's load is described in Section 1.6 C of this Exhibit 1.

On April 27, 2020, the Premier of Ontario provided a framework for "reopening" the province[8] which included a three-stage process:

- Stage 1: Protect and Support ($17 billion in target support)
- Stage 2: Restart (A gradual, staged approach)
- Stage 3: Recover (Long-term growth)

On June 15, 2020 and July 24, 2020, the Region, including the City moved to Phase 2 and Phase 3 of the recovery plan respectively, as permitted by the Government of Ontario.

As of the date of filing this Application, the Region is still in Stage 3. Nearly all businesses and public spaces have reopened, but with public health and workplace safety restrictions in place. High-risk venues and activities remain closed until they can safely resume operations. Indoor and outdoor gatherings are still limited.

A high proportion of Burlington's residential customers continue to be home during the day; and customers continue to experience the negative economic impacts of COVID-19, particularly those in the service industry. Consequently, BHI expects that COVID-19 will continue to materially impact BHI's operations and load for the remainder of 2020 and into 2021.

Throughout COVID-19, BHI, the OEB and the Government of Ontario have taken several courses of action to respond to COVID-19 to ensure uninterrupted electricity supply and the continued safe and reliable delivery of electricity to Ontarians.

1.2.7.2 Provincial Actions

To assist customers with paying their electricity bills, on March 24, 2020, the Government of Ontario announced an emergency order that electricity pricing for 45 days was 10.1¢/kWh at the on-peak, mid-peak and off-peak periods for electricity. This was originally in effect from March 24, 2020 to April 7, 2020 and subsequently extended to May 31, 2020.

[8] https://files.ontario.ca/mof-framework-for-reopening-our-province-en-2020-04-27.pdf

On March 25, 2020, The Ontario Energy Board established Account 1509 – Impacts Arising from the COVID-19 Emergency, with three sub-accounts, for electricity distributors to use to track any incremental costs and lost revenues related to the COVID-19 pandemic.[9]

On March 27, 2020, the OEB issued guidance on providing relief to customers during the COVID-19. Utilities were permitted to waive or lower late payment charges. Although BHI did not waive late payment charges, BHI accommodates customers in arrears through payment plans; increased awareness of support available to customers; and responded in a timely manner to customer requests, emergencies and concerns.

On June 1, the Government of Ontario made the following announcements:

(i) introduction of a new fixed electricity price of 12.8¢/kWh for time-of-use prices effective from June 1, 2020 to October 31, 2020;
(ii) establishment of the COVID-19 Energy Assistance Program ("CEAP") which made $9,000,000 and $8,000,000 respectively to support residential and small business customers struggling to pay their energy bills as a result of COVID-19.[10] BHI was allocated $63,235 and $59,455 respectively; and started accepting applications July 13, 2020 as mandated by the OEB; and
(iii) introduction of a program allowing customers to choose between time-of-use pricing and tiered rates for their electricity starting November 1, 2020. This was non-COVID related, however did provide customers more choice and the opportunity to lower their electricity bill. BHI began accepting applications on October 13, 2020.

The OEB issued new time-of use pricing on October 13, 2020 effective from November 1, 2020 to October 31, 2021.[11] BHI has used this pricing in the calculation of its Cost of Power as identified in Section 2.1.3.1 of Exhibit 2.

[9] Ontario Energy Board *Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency*, March 25, 2020
[10] EB-2020-0162, EB-2020-0185
[11] Ontario Energy Board, *Regulated Price Plan Price Report November 1, 2020 to October 31, 2021* October 13, 2020

1.2.7.3 BHI Actions

BHI responded quickly and effectively to COVID-19 to (i) ensure the safety of its employees, contractors and customers; and (ii) continue to deliver electricity safely and reliably and to the same standards in place prior to COVID-19. In addition to the impact to BHI and its customers and employees as a whole; significant changes in the Distribution Operations were required.

BHI Corporate

A Pandemic Planning Committee ("PPC") was struck in March 2020 and a Pandemic Preparedness/Response Plan ("COVID-19 Plan") was created to prepare for and respond to COVID-19 in an appropriate and timely manner. The key objectives of the COVID-19 Plan include achieving effective preparation and response through clarity, process familiarity and confidence for employees and other stakeholders, sharing appropriate information and modifying BHI operations and procedures to protect employees and the public. The COVID-19 Plan resulted in the following:

- Voluntary work from home option for some job functions. Supervisors offer a temporary work at home option as appropriate to their team. Employees opting to work at home sign an agreement prior to participation in this temporary work at home arrangement. As of the date of filing this Application, rotating between the home and office remains optional at a 50/50 maximum split;
- Regular, on-going employee communications. As of the date of filing this Application, 44 organizational communications have been issued since March 2020. BHI activated a Zoom software subscription to maintain external and internal communications;
- Completion of return to work assessments by the Human Resources ("HR") team. Prior to any employees returning to work after self-isolation or due to any type of illness, HR contacts the employee by phone for an interview the employee in order to complete the BHI's "Return to Work during Pandemic Screening Tool" created specifically for COVID-19;
- Work space upgrades with added Plexiglas, safety signage, web-cameras, along with appropriate acquisition and distribution of Personal Protective Equipment ("PPE");
- Purchase of additional sanitizing products for trades and office staff such as rubber gloves; and sanitizing wipes and gels;

- Enhanced nightly building cleaning to include sanitizing of all touchable surfaces including handrails, door knobs, desk and counter tops, keyboards, phones and mice;
- Implemented pre-entry COVID-19 screening of all “essential visitors” such as contractors; visitors are required to use a face covering when on BHI’s premises and visits are by pre-arranged appointment only; and
- Employees are required to conduct self-screening by reviewing posters placed at entrances, prior to entering BHI’s premises. These posters are used as a visual checklist to determine if an employee is cleared to enter the physical workplace. All employees are required to use a face covering on BHI’s premises when not at their desk or seated in a meeting room.

Distribution Operations

Several changes to workforce practices were made in Distribution Operations to respond to COVID-19, the intent of which was to segregate teams of employees in critical operation areas such that if one team contracted COVID-19, the other team(s) was unaffected and could continue to operate and maintain BHI’s distribution system. This concept is defined as “air-gapping”. Workforce practices were altered for each of Powerlines, Municipal Stations, Metering, the Control Room and Engineering as follows:

Powerlines:

Powerline crews were split into two teams, one working out of BHI’s office and one reporting to, and working from, a remote location set up specifically in response to COVID-19. This arrangement will be in place for the duration of COVID-19. A Powerline supervisor is dedicated to each team. Contracted Powerline crews are also distanced from both BHI Powerline teams - work assignments are not on the same project; and as such the Contracted Powerline crews have no contact with BHI’s Powerline crews. Material handling is separated for the three independent teams.

Each employee drives a separate vehicle, supplied with sanitary wipes for surfaces, soap and water for hand washing and hand sanitizer. Dedicated, separate washroom facilities were positioned throughout the City, as initially there was no access to restaurants or public facilities.

Municipal Stations:

Municipal Substation and Protection and Control staff, who typically work out of BHI's Head Office, were separated into three teams of two members each. Two of the teams continue to work remotely at one of BHI's substations, complete with a dedicated washroom, gear storage and changing area.

Metering:

Metering Technicians typically work individually, however due to COVID-19 they adhere to social distancing guidelines and do not enter BHI's head office. Social distancing is adhered to when contact with property owners and contractors is required. If they required use of the metering lab, social distancing is practice and lab equipment is sanitized before and after use.

Control Room:

Control Room staff were segregated into three teams that use separate workstations on alternating shifts. Workstations are sanitized before and after shifts. A separate back-up Control room, complete with washroom facilities, was established at a substation location for emergency use in case employees were not allowed to enter the Control Room at BHI's head office in the event of quarantine. The Control Room Supervisor is physically separated from all Control Room staff as an extra layer of precaution.

Engineering:

Engineering Technician staff, Supervisors and Managers were placed on a rotation with two thirds working from home and one third working from BHI's head office, in which social distancing is practiced. Engineering staff are permitted to attend meetings outside the building only if social distancing can be maintained at outdoor project site visits.

1.2.7.4 Impact of COVID-19

There have been several implications to BHI as a result of COVID-19 as described below.

<u>Impact on 2020 Distribution Revenues</u>

BHI has incurred lost revenue due to a decrease in consumption and demand for the GS<50 kW and GS>50 kW customer classes respectively, as a result of COVID-19 closures in Q2 and Q3. To date, some businesses remain closed and as of the date of filing, the financial impact of

COVID-19 in 2020 is uncertain. BHI deferred some of its distribution maintenance activities from Q2 to Q3 and Q4 at the outset of COVID-19 as it was unaware of the extent of the COVID-19 impact on distribution revenues. It has since resumed these activities and as of the date of filing expects to complete all maintenance and inspection activities as originally planned in 2020.

Impact on the Load Forecast

COVID-19 has had a material impact on BHI's energy and demand forecast in the 2020 Bridge and 2021 Test Years. This impact is discussed in detail in Section 1.6 C. of this Exhibit 1.

Impact on Operating Costs

BHI has incurred incremental operating costs in 2020 as a result of its response to COVID-19; specifically costs associated with (i) air-gapping crews by setting up separate control room and operations centres; (ii) implementing temporary work from home protocols; (iii) increasing cleaning services; and (iv) purchasing COVID-19 supplies such as hand sanitizer, wipes and masks. BHI has recorded these costs in the OEB's Account 1509 - Impacts Arising from the COVID-19 Emergency, Sub-account Other Costs ("Account 1509 – Other Costs)[12] which is to record incremental identifiable costs related to the COVID-19 emergency, including costs relating to bad debt expenses, and as such they are not included in 2020 OM&A. BHI increased its bad debt provision in 2020 to account for additional write-offs for small commercial customers expected as a result of COVID-19; however it has not recorded this in the Account 1509 – Other Costs. It will record bad debt expense in this account when incurred.

As previously stated, BHI expects that COVID-19 will continue to materially impact BHI's operations and load for the remainder of 2020 and into 2021. BHI will continue to record incremental costs in the Account 1509 – Other Costs; however BHI cannot predict with certainty the impact that the continuance of COVID-19 will have on the remainder of the 2020 Bridge Year and the 2021 Test Year. Capital expenditures are similarly affected.

[12] Ontario Energy Board *Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency*, March 25, 2020

Impact on Capital Expenditures

COVID-19 did not have a significant impact on BHI's actual and forecasted capital expenditures in the 2020 Bridge Year and the 2021 Test Year. BHI's Powerlines and Metering crews have continued to work since the start of COVID-19; crews were not sent home on a rotational basis as was the case with other LDCs. BHI did incur lower than expected system renewal expenditures as it deferred some of its proactive replacement work to mitigate cash flow risk associated with lost revenue as a result of COVID-19; however this was partly offset by reactive emergency replacement for primary underground cables and Municipal Substation cables.

Impact on Conservation and Demand Management

Conservation and demand management programs have also been impacted by COVID-19. On July 22, 2020 the MENDM issued a directive to the IESO mandating the extension of timelines for certain projects and related deadlines under the Conservation First Framework ("CFF") to June 30, 2021. These extensions are intended to offset the disruptions caused by COVID-19 for participants and those businesses involved in delivering CDM programs. The impact to CDM and LRAMVA is discussed further in Section 4.6 of Exhibit 4.

Impact to Filing Date of this Application

BHI was originally scheduled to file its Application on August 31, 2020. However due to COVID-19, BHI had to reallocate resources to address key customer, operational and staffing issues as identified above. In fact, the majority of BHI's work efforts from March to June were related to COVID-19 response and preparedness. BHI requested a filing extension to November 27, 2020[13] which was approved by the OEB on June 1, 2020.[14] BHI is filing this Application on October 30, 2020, one month ahead of schedule and respectively requests that the OEB approves its proposed rates effective May 1, 2021, despite the delay in filing from August 30, 2020.

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[13] BHI Letter to the OEB: *EB-2020-0007 Burlington Hydro Inc. Cost of Service - Extension of Filing Deadline*, May 29, 2020

[14] OEB Letter: *Burlington Hydro Inc.'s (Burlington Hydro) Request for an Extension to the Filing of its Cost of Service Application for 2021 Rates Ontario Energy Board File Number: EB-2020-0007,* June 1, 2020

1.2.8 Realized Efficiencies and Improvements

BHI has realized efficiencies and made improvements to its business processes as follows:

- Mitigated the cost associated with the transition to monthly billing by increasing the penetration of e-billing, and absorbed the incremental effort required to produce monthly bills within the existing headcount in the department;
- Changed its process for field collection services to (i) move to an hourly versus piece rate and (ii) eliminate hand delivery; to offset the lost revenue as a result of the elimination of the collection of account charge;
- Enhanced its credit management process to mitigate costs associated with bad debt;
- Realized efficiencies in its benefits program;
- Reduced vehicle operations and maintenance costs due to regularly scheduled maintenance of vehicles;
- Maintained OM&A costs in certain departments at lower than the cost of inflation since its last rebasing application (Accounting, Facilities, Fleet, Metering, and Stations);
- Implemented a new front end phone service including an enhanced Interactive Voice Response ("IVR") in 2016;
- Replaced its telephone infrastructure in 2019 and implemented cloud based call centre management;
- Implemented a new Payroll and Human Resource Information System ("HRIS") to consolidate core HR functions into one system;
- Implemented a new Geographic Information System ("GIS") in January 2020 with the following benefits to improve business processes through new system functionality. This change was driven by software incompatibility and obsolescence of the legacy GIS.
- Implementing a new Customer Information System ("CIS") in 2020 to provide enhanced services to customers;
- Leveraged an ACA to identify assets in Very Poor and Poor condition and mitigate outages as a result of failures due to defective equipment; and
- Introduced two new planning tools – the Program Evaluation Tool and Project Prioritization Tool to evaluate and prioritize capital programs and projects; and optimally allocate limited capital dollars and resources.

1.3 CUSTOMER SUMMARY

In accordance with the Chapter 2 Filing Requirements, BHI provides a complete summary of its Application below. This Customer Summary is also attached as a stand-alone document Attachment1_Customer Summary_BHI_10302020.

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

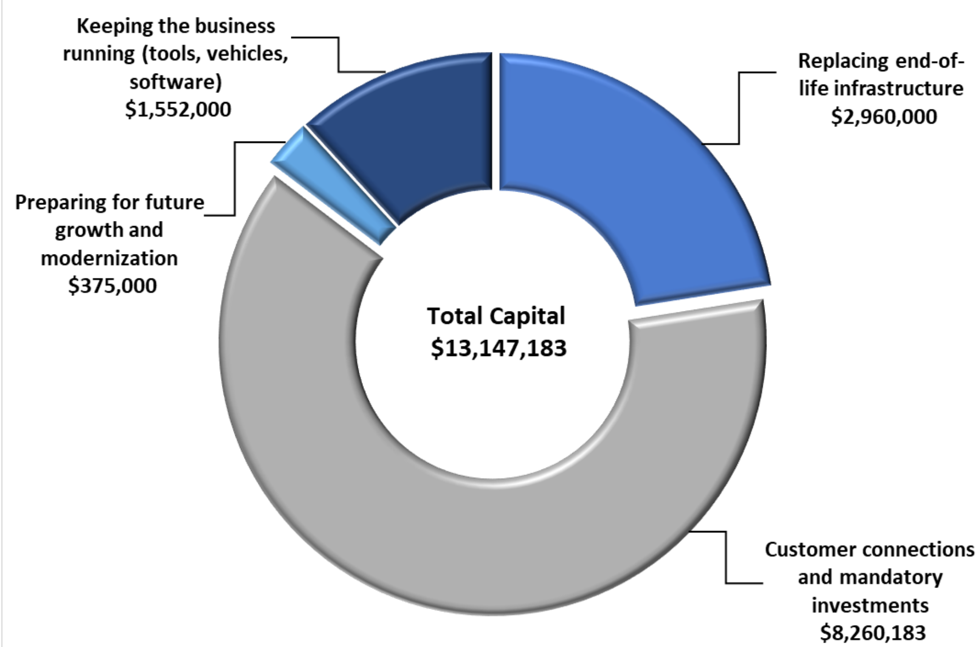
Over the course of the 2021-2025 period, BHI's investment needs are driven by deteriorating infrastructure, ongoing demand for new connections to the grid, changing electricity demand in pockets of the city, and technology changes.

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).

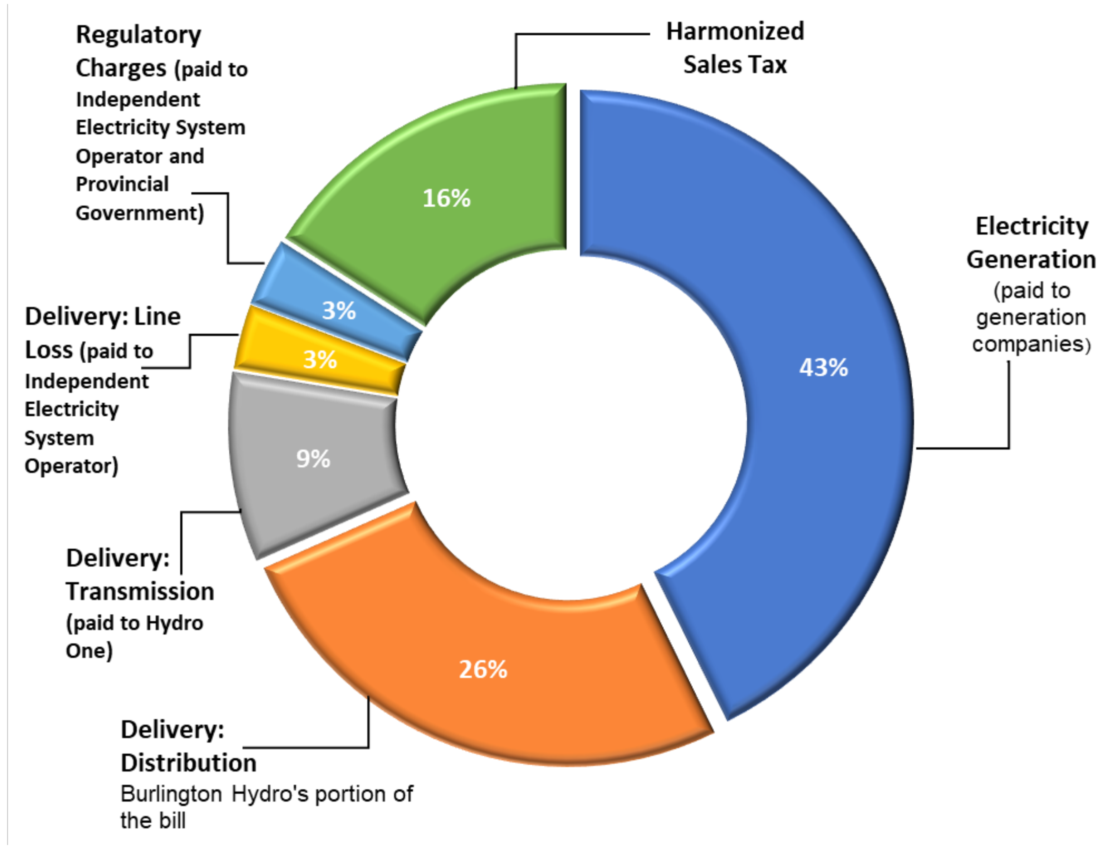
The proposed total bill increases from 2020 to 2021 for residential and small business (GS<50 kW) customers are:

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.

1.4 ADMINISTRATION

In accordance with the Ontario Energy Board's ("OEB's") *Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Applications – Chapter 2 Cost of Service*, dated May 14, 2020, ("the Chapter 2 Filing Requirements"), this section provides information relating to the administration of this Application.

1.4.1 Certification of Evidence

BHI provides certification of the evidence filed in this Application in Appendix C of this Exhibit 1.

1.4.2 Primary Contact Information

Sally Blackwell
Vice President, Regulatory Compliance & Asset Management
Burlington Hydro Inc.
1340 Brant Street
Burlington, Ontario L7R 3Z7
Telephone: (905) 336-4373
Fax: (905) 336-4399
Email: sblackwell@burlingtonhydro.com

1.4.3 Legal Representation

Charles Keizer
Partner
Torys LLP
79 Wellington Street West #3300
Toronto, Ontario M5K 1N2
Email: ckeizer@torys.com

1.4.4 Internet Address and Media Accounts

BHI's main webpage is the following: www.burlingtonhydro.com.

All evidence and Cost of Service Application documents will be available in the Regulatory Affairs section of BHI's website:

https://www.burlingtonhydro.com/about/bhi-the-company/regulatory-affairs.html.

The social media accounts maintained by BHI are as follows:

- Twitter https://twitter.com/BurlingtonHydro
- LinkedIn https://www.linkedin.com/company/burlington-hydro-inc-
- YouTube https://www.youtube.com/user/burlingtonhydro

1.4.5 Material Impacts on Customers

The proposals set forth in this Application will change the rates for all customer classes; however there are no proposed changes that will result in bill impacts which exceed the 10% total bill impact threshold and which would consequently have a material impact on customers.

1.4.6 Materiality Threshold

Section 2.0.8 – Materiality Thresholds of the Chapter 2 Filing Requirements states that the materiality threshold relates to the revenue requirement impact of the expenditure. BHI's applicable materiality threshold is defined as 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. BHI's distribution service revenue requirement for 2021 in this Application is $35,529,884 which equates to a materiality threshold of $180,000. BHI provides its materiality threshold for various components of its Application in Table 3 below. BHI provides additional details below the threshold in certain situations in this Application to ensure that the OEB has the information it needs to properly assess and deliberate on the application; these situations are identified in each Exhibit as applicable.

Table 3 – Materiality Threshold

Description	2021 Test Year
Proposed Distribution Revenue Requirement	$35,529,884
0.5% of Proposed Distribution Revenue Requirement	$177,649
Revenue Requirement Impact for Materiality Threshold	**$180,000**

Description	Rate Base	WCA (COP and OM&A)	Capital Expenditures	Revenues	OM&A and Depreciation	PILS
Materiality Threshold	$5,300,000	$37,000,000	$2,500,000	$180,000	$180,000	$244,898
Revenue Requirement Impact	$180,000					

1.4.7 Publication and Notice

BHI recommends that the Notice of Application and Hearing for this proceeding be published in the following newspapers:

- the Hamilton Spectator, which has the highest paid circulation in BHI's service area (specifically, an estimated readership of 387,000 and an estimated weekly circulation of 633,000); and
- the Burlington Post, which is the free local community newspaper with the highest un-paid circulation in BHI's service area (specifically, an estimated weekly circulation of 40,000).

BHI also proposes to post the Application on its website at: http://www.burlingtonhydro.com.

1.4.8 Bill Impacts

BHI provides the bill impacts for a typical residential customer using 750 kWh per month and for a General Service<50 kW ("GS<50 kW") customer using 2000 kWh per month in Table 4 below. BHI also provides bill impacts based on alternative consumption profiles and customer groups which reflect the consumption patterns of its customers.

Table 4 – Bill Impacts

Class	kWh	kW	Distribution (Fixed and Volumetric) Sub-Total A			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$27.31	$30.03	$2.73	10.0%
Residential (10th percentile)	295		$26.90	$30.03	$3.13	11.7%
GS<50 kW	1500		$51.34	$56.80	$5.46	10.6%
GS<50 kW	2000		$59.39	$65.60	$6.21	10.5%
GS>50 kW	36700	200	$725.38	$819.75	$94.37	13.0%
Street Lighting	175	0.22	$1.42	$1.85	$0.43	30.2%
Unmetered Scattered Load	2000		$33.25	$25.80	($7.45)	(22.4%)

Class	kWh	kW	Total Bill (after HST and OER)			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$114.56	$117.02	$2.46	2.1%
Residential (10th percentile)	294.7		$58.55	$61.19	$2.64	4.5%
GS<50 kW	1500		$224.67	$230.07	$5.41	2.4%
GS<50 kW	2000		$291.97	$298.31	$6.34	2.2%
GS>50 kW	36700	200	$5,719.86	$5,956.55	$236.68	4.1%
Street Lighting	175	0.22	$26.51	$27.13	$0.63	2.4%
Unmetered Scattered Load	2000		$270.28	$265.53	($4.75)	(1.8%)

1.4.9 Form of Hearing

BHI requests that this Application be disposed of by way of a written hearing. It is BHI's view that this would be the most efficient means to reach a Decision.

1.4.10 Requested Effective Date

BHI is requesting approval of the proposed distribution rates and other charges set out in this Application effective May 1, 2021.

BHI requests that its current (i.e., 2020) rates provided in Appendix B of Exhibit 8 be declared interim effective May 1, 2021, as necessary, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2021; and that it be permitted to establish an account to recover any differences between the interim rates and the actual rates effective May 1, 2021 based on the OEB's Decision and Order.

1.4.11 OEB Chapter 2 Appendices

BHI has filed the OEB's Chapter 2 Appendices in accordance with the Chapter 2 Filing Requirements. These are attached as Live Excel and PDF files as follows:

- Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020 ("Chapter 2 Appendices - Main") includes
    - all Chapter 2 Appendices except the ones in Attachments 3-6 listed below.

- Attachment3_2C_OEB_Chapter2Appendices_BHI_10302020 ("Chapter 2 Appendices - 2C") is filed separately so that this tab could be completed concurrently with the remaining tabs of the Chapter 2 Appendices, and includes
    - App.2-C_DepExp

- Attachment4_2I_OEB_Chapter2Appendices_BHI_10302020 ("Chapter 2 Appendices - 2I") is filed separately so that these tabs could be completed concurrently with the remaining tabs of the Chapter 2 Appendices, and includes
    - App_2-I LF_CDM
    - App.2-IA_Load_Forecast_Instrct
    - App.2-IB_Load_Forecast_Analysis

- Attachment5_IFRS_OEB_Chapter2Appendices_BHI_10302020 ("Chapter 2 Appendices - IFRS") is filed separately as BHI requested these from the OEB after it had had populated the majority of the other tabs in the Chapter 2 Appendices and did not have time to repopulate every tab in the revised model containing the IFRS tabs, and includes
  - App.2-EA_Account 1575 (2015)
  - App.2-YA_IFRS Transition Costs

- Attachment6_2Z_OEB_Chapter2Appendices_BHI_10302020 ("Chapter 2 Appendices - 2Z") is filed separately as the OEB updated its model for these two tabs after BHI had populated the majority of the other tabs in the Chapter 2 Appendices, and includes
  - App.2-ZA_Com. Exp. Forecast
  - App.2-ZB_Cost of Power

1.4.12 Changes to Methodologies used in Previous Applications

BHI filed the 2014 Test Year in its 2014 Cost of Service under Revised CGAAP which incorporated changes to the useful lives of its capital assets and changes to its capitalization polices with respect to overheads. These accounting policy changes were made effective January 1, 2013 as directed by the OEB.[15] BHI transitioned to IFRS as of January 1, 2015 and has prepared this Application on that basis. BHI has completed the OEB's Chapter 2 Appendices using the accounting standards identified in Table 5 below.

[15] OEB Letter: *Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*, July 17, 2012

Table 5 – Accounting Standards

Year	Accounting Standards
2014 Cost of Service (EB-2013-0115)	Revised CGAAP (CGAAP with MIFRS depreciation and capitalization policies)
2014 Actuals	
2015 Actuals	MIFRS
2016 Actuals	
2017 Actuals	
2018 Actuals	
2019 Actuals	
2020 Bridge Year	
2021 Test Year	

1.4.12.1 Differences between Revised CGAAP and MIFRS

There are differences between Revised CGAAP and MIFRS, not captured in the accounting policy changes described above, which BHI is incorporating into this Application for the first time. These differences are described below.

Employee Future Benefits[16]

Under IFRS, actuarial gains and losses of a benefit plan are recognized in Other Comprehensive Income. Under CGAAP, actuarial gains and losses were amortized over the average remaining service lives of employees in the plan. BHI did not reflect these changes in 2014 Revised CGAAP and MIFRS statements as the income statement difference between the two accounting methodologies was not material – the adjustment to administration expenses was $19,097 as identified in Table 6 below.

Leases[17]

Under both IFRS and CGAAP, lease classification depends on whether substantially all of the risks and rewards incidental to ownership of a leased asset have been transferred from the lessor to the lessee, and is made at inception of the lease. However, under IFRS all major leases are recorded on the balance sheet as capital leases with few lease recognition

[16] IFRS - *IAS 19, IFRIC 14* and CGAAP - *HB 3461, EIC-134*
[17] IFRS - *IAS 17, IFRS 16, IFRIC 4, SIC–15, SIC–27* and CGAAP - *HB 3065, EIC-19, EIC-21, EIC-150*

exemptions for lessees. Certain leases, previously classified as operating leases under CGAAP, were classified as capital leases under IFRS.

BHI did not reflect these changes in 2014 Revised CGAAP and MIFRS statements as the balance sheet and income statement difference between the two accounting methodologies was not material – the adjustment to the balance sheet and income statement was $20,697 and ($20,697) respectively as identified in Table 6 below.

Derecognition of Assets/Disposals[18]

Under IFRS, an item of Property Plant and Equipment ("PP&E") is derecognized when it is disposed of or when no future economic benefits are expected from its continued use or retention. Under CGAAP, for rate regulated entities using a pooled approach to fixed asset recognition, PP&E assets were removed at the end of their depreciable lives. Consequently BHI records losses or gains on disposals under MIFRS that it did not record under Revised CGAAP.

In addition, to the above differences, BHI recorded allocated depreciation expense of $396,790 in OM&A under revised CGAAP and in depreciation expense under MIFRS. These amounts as follows:

- Software Amortization – Administration - $260
- Software Amortization – Information Technology Program - $55,438
- Software Amortization – Engineering Program - $262,990
- Software Amortization – Fleet - $78,102

BHI has the option of filing two sets of Chapter 2 Appendices for the transition year (2014) - one under revised CGAAP and one under MIFRS, depending on the materiality of impacts as identified in Tab "App.2-B_Acctg Instructions" of the Chapter 2 Appendices. BHI provides the difference between 2014 Revised CGAAP and 2014 MIFRS in Table 6 below by category and account.

[18] IFRS - *IAS 16, IAS 23, IFRIC 1, IFRIC 18* and CGAAP - *HB 1506, HB 3061, HB 3110, HB 3831, HB 3475*

Table 6 – 2014 Revised CGAAP vs. MIFRS

Change #	Category	Account Name	Account	Entry to Convert Revised CGAAP to MIFRS: Balance Sheet $ DR/(CR)	Entry to Convert Revised CGAAP to MIFRS: Income Statement $ DR/(CR)
1	Employee Future Benefits	Employee Future Benefits Liability	2306	(652,126)	
		Accumulated OCI	3090	465,277	
		Retiree Benefits Actuarial Adjustment	5645		19,097
		Retained Earnings	3045	3,611	
		Future Income Taxes	2350	(676,503)	
		Regulatory Liability-Future Taxes	2320	854,196	
		Future Income Taxes - 2014	6115		(13,552)
2	Leases	OH - Primary Structures	1835	(44,313)	
		UG - Primary Conduit	1840	(15,924)	
		Trucks - Capital/Capital Lease	1930/2325	146,452	
		Accumulated Depreciation	2105	(52,206)	
		Accrued Liabilities	2220	200	
		Current Portion of LTD	2260	(58,530)	
		Retained Earnings	3045	3,624	
		OH Lines and Feeders - Trucks	5025		(46,157)
		Depreciation Expense	5705		34,650
		Interest Expense - Other	6035		32,205
3	Allocated Depreciation in OM&A	Depreciation Expense	5705		396,790
		Amortization Admin & IT Software	5665		(55,698)
		Amortization Engineering Software	OM&A		(262,990)
		Amortization Fleet	OM&A		(78,102)
4	Disposals	OH Primary Structures	1830	(8,808)	
		OH Primary Devices	1835	(8,413)	
		UG Primary Conduit	1840	(1,343)	
		UG Primary Conductor	1845	(828)	
		Transformers	1850	(159,283)	
		UG Secondary	1855	(3,027)	
		IFRS-CGAAP Transitional PP&E	1575	82,451	
		Accumulated Depreciation	2105	99,252	
		Loss on Disposal	4360		82,451
		Regulatory Credits	4310		(82,451)
Total				**(26,242)**	**26,242**

The only entry which materially impacts this Application is the entry related to disposals (on a cumulative basis from 2014 to the 2021 Test Year); and the only entry which produces a material difference between Revised CGAAP and MIFRS financial statements is depreciation expense. BHI discusses each of these in turn below.

1.4.12.2 Impact of Disposals

As previously mentioned, under IFRS, retirement of assets (pool of like assets) must be recorded each year, whereas under CGAAP no such adjustment was required.

BHI recorded the amounts for the gains and losses on de-recognition of assets accumulated since the transition to IFRS in Account 1575 IFRS-CGAAP Transitional PP&E amounts. This is discussed in further detail in Section 9.1 of Exhibit 9. BHI has completed Tab "App.2-EA_Account 1575 (2015) of the Chapter 2 Appendices - IFRS. BHI did not reflect these changes in separate Fixed Asset Continuities for 2014 Revised CGAAP and 2014 MIFRS as they were immaterial for 2014 – loss on disposition for 2014 was $82,451 as identified in Table 6 above.

1.4.12.3 Impact of Depreciation Expense

As previously mentioned, BHI recorded allocated depreciation expense of $396,790 in OM&A under revised CGAAP and in depreciation expense under MIFRS. In both cases the offset to this entry was to accumulated depreciation and therefore there is no difference between the accumulated depreciation in the 2014 Fixed Asset continuity statements under Revised CGAAP and MIFRS. However, BHI has filed 2014 Fixed Asset continuity statements in both CGAAP and MIFRS to show a reconciliation of depreciation expense under each accounting methodology.

BHI has included 2014 Revised CGAAP and MIFRS in the below Chapter 2 Appendices to identify the differences between Revised CGAAP and MIFRS discussed above.

- App.2-BA_Fixed Asset Continuities
- App.2-JB_OM&A_Cost_Drivers
- App.2-JC_OM&A Programs

1.4.13 OEB Directions from Previous Decisions and/or Orders

Below is a summary of directives from previous decisions and/or orders and a description of how such directives are addressed by BHI in this Application.

1.4.13.1 Accounting Order – Costs - Implementation of Monthly Billing

On April 15, 2015 the OEB announced that by the end of 2016, all electricity distributors in Ontario will be required to bill their customers on a monthly basis.[19]

The net incremental costs associated with this transition were outside of the base on which BHI's distribution rates were set in its 2014 Cost of Service (EB-2013-0115), and as such BHI

[19] https://www.oeb.ca/sites/default/files/news_release_Monthly_Bill_20150415_0.pdf

applied to the OEB to establish a deferral account to record these costs. The OEB approved this request and directed BHI "to record the costs and savings incurred from the transition to monthly billing in a deferral sub-account of Account 1508" until its next cost-based rate order.[20]

The OEB, in its Decision, also indicated that the costs recorded in this account will be subject to a prudency review at the time of BHI's next rebasing application, which is this Application. BHI proposes to dispose of the balance in this account to December 31, 2019. This disposition is discussed in further detail in Exhibit 9.

1.4.13.2 Accounting Order – Lost Revenue - Collection of Account Charges

The Collection of Account charge was intended to cover the field costs, or part of the costs, of additional collection activities that are beyond the routine of a distributor as a result of an individual customer's non-payment of its account.[21] On February 23, 2017, the OEB issued a letter[22] indicating its intent to launch a review of customer service rules for the electricity and gas sectors, including the development of disconnection rules. On the same day, the OEB issued its decision and order[23] to amend all electricity distribution licenses to ensure that residential customers were not disconnected for non-payment during the February 24, 2017 to April 30, 2017 winter period. During that same period, the Collection of Account charge was also to be waived. In its subsequent decision and order[24] on November 2, 2017, the OEB further amended all electricity distributors' licenses to prohibit the disconnection of residential customers for reason of non-payment from November 15 to April 30 (Disconnection Ban Period) on a go forward basis. The waiving of the Collection of Account charge was also to apply on a go forward basis during the Disconnection Ban Period. On March 14, 2019, the Board issued a notice of amendments to codes and a rule amendment to the Distribution System Code, Standard Supply Service Code, Unit Sub-Metering Code, and Gas Distribution Access Rule

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[20] Decision and Rate Order EB-2016-0384, April 20, 2017, p15

[21] Report of the Ontario Energy Board - *Review of Customer Service Rules for Utilities, Phase 1*, EB-2017-0183, September 6, 2018

[22] Letter regarding *Winter Disconnections and Launch of Review of Customer Service Rules*, February 23, 2017

[23] Decision and Order, EB-2017-0101, *Amending Electricity Distributor Licenses to Prohibit Disconnection of Residential Customers and Related Matters*, February 23, 2017

[24] Decision and Order, EB-2017-0318, *Amending Electricity Distributor Licenses to Prohibit the Disconnection of Residential Customers and Related Matters*, November 2, 2017

(and Associated Rate Order) ("the Notice").[25] These amendments were issued as a result of the OEB's Phase 1 review of its customer service rules and associated service charges for licensed electricity distributors, rate-regulated natural gas distributors and unit sub-meter providers. The associated rate order eliminated the Collection of Account charge effective July 1, 2019.

BHI included revenue associated with the Collection of Account charge as part of its revenue offsets in its 2014 cost of service rate application. The inability to recover this revenue due to the Disconnection Ban Period and the elimination of the Collection of Account charge results in a shortfall in revenue requirement until BHI's next rebasing. As such, BHI applied to establish a deferral account to record lost revenues resulting from the elimination of the Collection of Account charge. The OEB approved the establishment of the deferral account effective July 1, 2019.[26] BHI proposes to dispose of the balance in this account to December 31, 2019. This disposition is discussed in further detail in Exhibit 9 in addition to any questions arising from the OEB's Decision and Order.

1.4.13.3 Accounting Guidance – OEB Cost Assessment

The OEB revised its Cost Assessment Model effective April 1, 2016[27] which materially changed the amount charged to LDCs for the OEB Annual Assessment. The OEB established a sub account of Account 1508 - OEB Cost Assessment Variance - for LDCs to record any material differences between the OEB Annual Assessment currently built into rates, and Annual Assessments that resulted from the application of the new cost assessment model effective April 1, 2016. BHI proposes to dispose of the balance in this account to December 31, 2019. This disposition is discussed in further detail in Exhibit 9.

1.4.13.4 Accounting Guidance – Wireline Pole Attachment Charges

The OEB set a new province-wide wireline pole attachment charge for carriers of $43.63 per pole per year effective January 1, 2019 in its *Report of the Ontario Energy Board – Wireline*

[25] Notice of amendments to codes and a rule amendment to the Distribution System Code, Standard Supply Service Code, Unit Sub-Metering Code, and Gas Distribution Access Rule (and Associated Rate Order) EB-2017-0183
[26] Decision and Order, EB-2019-0179
[27] OEB Letter re *Revisions to the Ontario Energy Board Cost Assessment Model*, February 9, 2016

Pole Attachment Charges dated March 22, 2018.[28] The new charge applied to all local distribution companies (LDCs) that had not received OEB approval for a distributor-specific pole attachment charge. As a transitional measure, to help mitigate the impact of the increase from the previous charge of $22.35 to the new charge of $43.63, LDCs without a distributor-specific charge were directed to charge a province-wide pole attachment charge of $28.09 per pole per year effective from September 1, 2018 until December 31, 2018.

BHI's last rebasing application was in 2014 at which time it was charging the province wide pole attachment charge of $22.35 per pole per year. The specific service charge revenues associated with this pole attachment charge were recorded as a revenue offset. As such, with the increase in the province-wide wireline pole attachment charge for carriers effective September 1, 2018, BHI would be collecting incremental revenue as compared to that which was approved in rates. In a letter issued March 22, 2018[29], the OEB instructed distributors to record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charges. It also directed distributors to refund the closing balance in the distributor's next cost of service application. The OEB provided accounting guidance in its letter *Accounting Guidance on Wireline Pole Attachment Charges,* dated July 20, 2018; and created a new variance account, Account 1508 – Sub Account – Pole Attachment Revenue Variance to record the incremental revenue arising from the changes to the pole attachment charge. BHI adhered to this accounting guidance and is proposing to dispose of the balance in this account in this Application. This disposition is discussed in further detail in Exhibit 9.

1.4.13.5 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

BHI rebased under revised CGAAP (under the new capitalization and depreciation policies consistent with the OEB letter dated July 17, 2012)[30] in its last rebasing application (EB-2013-0115). As such, it disposed of its balances related to new capitalization and depreciation polices, as recorded in Account 1576 – Accounting Changes under CGAAP, at that time.

[28] EB-2015-0304

[29] OEB Letter - *Updated Pole Attachment Charge for Wireline Pole Attachments OEB File Number: EB-2015-0304*, March 22, 2018

[30] OEB Letter: *Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*, July 17, 2012

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. BHI is requesting disposition and discontinuance of this account in this Application. Further details are provided in Exhibit 9.

1.4.14 Conditions of Service

BHI confirms that there are no rates or charges listed in its Conditions of Service that are not on its Tariff of Rates and Charges. The current version of BHI's Conditions of Service is available on its website: https://burlingtonhydro.com/conditions-of-service.html

1.4.15 Corporate and Utility Organizational Structure

BHI was incorporated and wholly transferred into the ownership of the City of Burlington on January 1, 2000 as a for-profit company. The City created a holding company, originally Burlington Hydro Electricity Inc. ("BHEI"), and since 2019, Burlington Enterprises Corporation ("BEC"), to oversee two subsidiary companies: a regulated "wires" company, Burlington Hydro Inc., and an unregulated company, Burlington Electricity Services Inc.

In December of 2018, the OEB issued guidance for regulated utility governance, which included new mandatory reporting and record-keeping requirement for utilities.[31] As a result of this guidance, the BHEI leadership team and Board brought forward recommended governance changes to City Council in June 2019 that would, if adopted, better align with the OEB utility governance model. These changes were approved and became effective on October 15, 2019. There was no change to the overall operation of the corporation; however the following governance changes reflecting best practices from the OEB guidance were implemented:

- Increased the number of independent (of the shareholder and affiliate) Board members appointed to BHI so that the majority of those directors are independent;
- Increased the size of the BHI Board of Directors from three directors to seven; and

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[31] Report of the OEB *Best Practices regarding Governance of OEB Rate Regulated Utilities OEB File Number: EB-2014-0255*, December 20, 2018

- Board decision making and the majority of Board meetings take place through BHI (previously at the holding company).

Figure 4 below identifies the corporate organizational structure of BEC, including Board of Directors representation for BEC and BHI; with a comparison to the previous model.

1 **Figure 4 – BHI Revised Corporate Model**

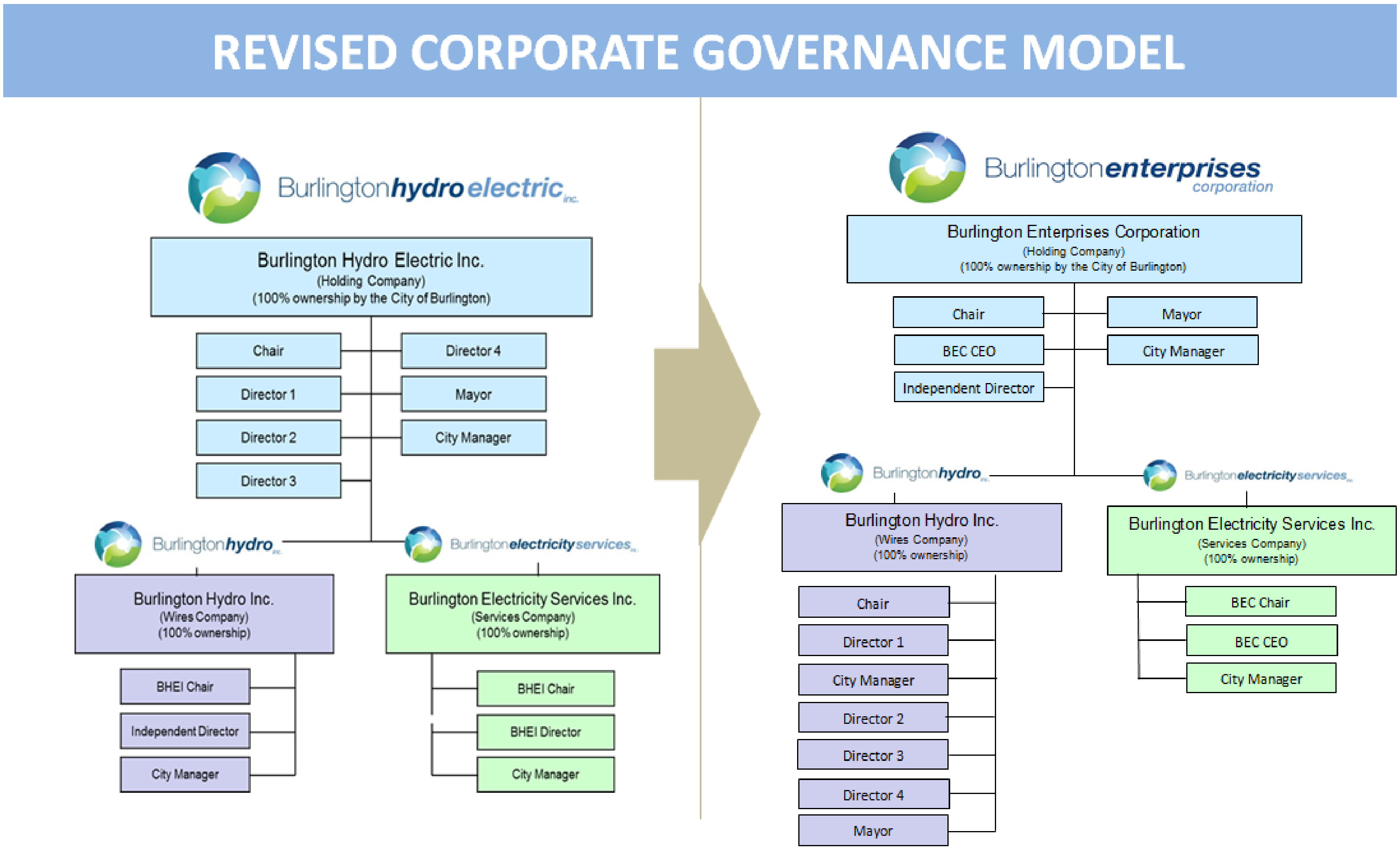
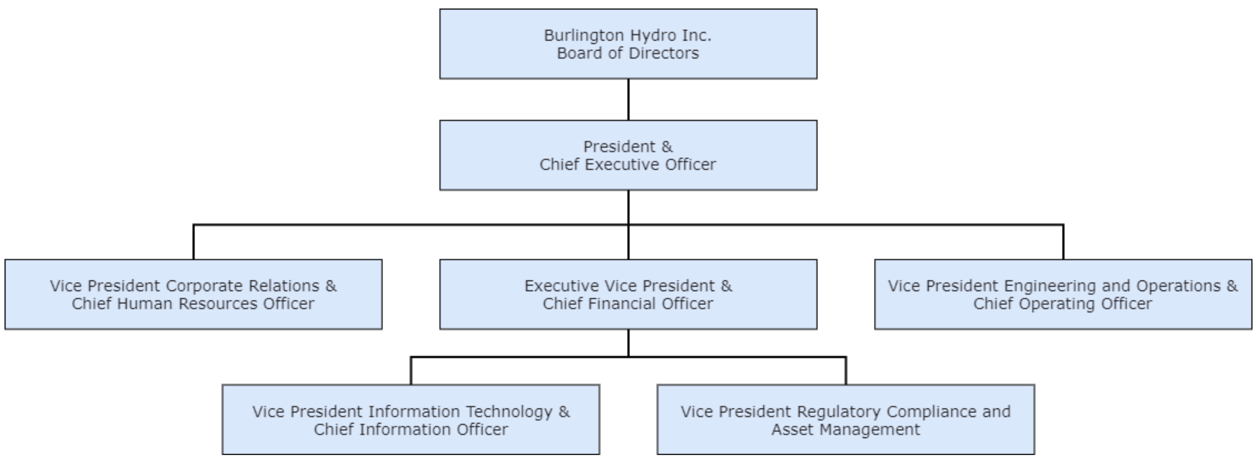


Figure 5 identifies the executive and senior management positions within the utility, and reporting relationship between the utility and parent company.

Figure 5 – BHI Corporate Structure



1.4.16 Specific Relief Requested

This Application is submitted pursuant to section 78 of the Ontario Energy Board Act, 1998. Herein, BHI is seeking the following specific approvals, which are also separately identified in Appendix 2-A of the Chapter 2 Appendices and clearly documented throughout applicable sections of this Application.

1. Approval of the 2021 Test Year revenue requirement as proposed in Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency as follows:
    a. Approval of the 2021 Test Year Service revenue requirement of $37,220,971;
    b. Approval of the 2021 Test Year Base revenue requirement of $35,529,884; and
    c. Approval of the 2021 Revenue offsets of $1,691,087
2. Approval of 2021 distribution rates and charges, effective May 1, 2021, as proposed in Appendix C - Proposed Tariff of Rates and Charges of Exhibit 8;
3. Approval of BHI’s Distribution System Plan filed as Appendix A in Exhibit 2;
4. Approval for an Advanced Capital Module (“ACM”) to implement a new Enterprise Resource Planning system (“ERP”) as set out in Exhibit 2, Section 2.2.3;

5. Approval of the inclusion into the 2021 opening rate base of BHI's Connection Cost Recovery Agreement ("CCRA") payments associated with the Tremaine TS; as documented in Exhibit 2, Section 2.2.4;
6. Approval of the inclusion into the 2021 opening rate base of BHI's purchase of two new breakers at the Tremaine TS as documented in Exhibit 2, Section 2.2.4;
7. Approval of the 2021 load forecast as documented in Exhibit 3;
8. Approval to continue to use the OEB established deferral Accounts (USoA 1509) to record impacts arising from the COVID-19 Emergency[32] not incorporated into this Application, from May 1, 2021 onwards, including the Sub-Account *Lost Revenues Arising from the COVID-19 Emergency for Electricity Distributors and Natural Gas Distributors* to record lost revenues as compared to the load forecast approved in this Application;
9. Approval to incorporate a reduction of 4.4 FTE and associated salaries and benefits of $572,068 in the 2021 Test year to smooth out the impact of differences in FTE over the 2021-2025 Price Cap IR period;
10. Approval to modify the description of certain Specific Service Charges as set out in Section 8.6 of Exhibit 8;
11. Approval of a revised loss factor as identified in Section 8.9 of Exhibit 8;
12. Approval of updated Retail Transmission Service Rates ("RTSRs"), as identified in Section 8.3 of Exhibit 8;
13. Approvals related to deferral and variance accounts, as set out in Exhibit 9: Deferral and Variance Accounts:
    a. Approval for the clearance of the balances recorded in certain Group 1 deferral and variance accounts of $2,433,347 on an interim basis by means of class-specific rate riders and manual adjustments, effective May 1, 2021 to April 30, 2023, as identified in Section 9.3 of Exhibit 9;
    b. Approval for the clearance of the balances recorded in certain Group 2 deferral and variance accounts of $2,708,451 by means of class-specific rate riders effective from May 1, 2021 to April 30, 2023 as follows:

[32] OEB Letter *Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency* , March 25, 2020

i. Approval for the clearance of the balance in its Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") of $1,039,196, resulting from its Conservation and Demand Management ("CDM") activities up to December 31, 2020 as identified Section 4.6.2 of Exhibit 4;

ii. Approval for the clearance of the balance in its USoA Account 1575 - IFRS-CGAP Transitional PP&E Amounts of $829,462, resulting from BHI's transition to IFRS by means of class-specific rate riders effective from May 1, 2021 to April 30, 2023, as identified in Section 9.1 of Exhibit 9; and

iii. Approval for the clearance of the balance in all remaining Group 2 accounts of $839,793 as identified in Section 9.3 of Exhibit 9;

c. Approval of the continuation of certain deferral and variance accounts, as set out in Section 9.0.5 of Exhibit 9;

d. Approval of discontinuation of certain deferral and variance accounts, as set out in Section 9.0.5 of Exhibit 9; and

14. Approval to make its current (i.e., 2020) rates provided in Appendix B of Exhibit 8 interim effective May 1, 2021, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2021;

15. Approval to establish an account to recover any differences between the interim rates and the actual rates effective May 1, 2021 if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2021; and

16. Approval of other items or amounts that may be requested by BHI in the course of the proceeding, and such other relief or entitlements that the OEB may grant.

BHI provides a PDF copy of this Appendix 2-A of the OEB's Chapter 2 Appendices below.

1.4.16.1 Appendix 2-A List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Burlington Hydro Inc. is seeking the following approvals in this application:

1		Approval of the 2021 Test Year revenue requirement as proposed in Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency as follows:
1	a	Approval of the 2021 Test Year Service revenue requirement of $37,220,971
1	b	Approval of the 2021 Test Year Base revenue requirement of $35,529,884
1	c	Approval of the 2021 Revenue offsets of $1,691,087
2		Approval of 2021 distribution rates and charges, effective May 1, 2021, as proposed in Appendix C - Proposed Tariff of Rates and Charges of Exhibit 8
3		Approval of BHI’s Distribution System Plan filed as Appendix A in Exhibit 2
4		Approval for an Advanced Capital Module (“ACM”) to implement a new Enterprise Resource Planning system (“ERP”) as set out in Exhibit 2, Section 2.2.3
5		Approval of the inclusion into the 2021 opening rate base of BHI’s Connection Cost Recovery Agreement (“CCRA”) payments associated with the Tremaine TS; as documented in Exhibit 2, Section 2.2.4
6		Approval of the inclusion into the 2021 opening rate base of BHI’s purchase of two new breakers at the Tremaine TS as documented in Exhibit 2, Section 2.2.4
7		Approval of the 2021 load forecast as documented in Exhibit 3
8		Approval to continue to use the OEB established deferral Accounts (USoA 1509) to record impacts arising from the COVID-19 Emergency not incorporated into this Application, from May 1, 2021 onwards, including the Sub-Account Lost Revenues Arising from the COVID-19 Emergency for Electricity Distributors and Natural Gas Distributors to record lost revenues as compared to the load forecast approved in this Application

9		Approval to incorporate a reduction of 4.4 FTE and associated salaries and benefits of $572,068 in the 2021 Test year to smooth out the impact of differences in FTE over the 2021-2025 Price Cap IR period
10		Approval to modify the description of certain Specific Service Charges as set out in Section 8.6 of Exhibit 8
11		Approval of a revised loss factor as identified in Section 8.9 of Exhibit 8
12		Approval of updated Retail Transmission Service Rates (“RTSRs”), as identified in Section 8.3 of Exhibit 8
13		Approvals related to deferral and variance accounts, as set out in Exhibit 9: Deferral and Variance
13	a	Approval for the clearance of the balances recorded in certain Group 1 deferral and variance accounts of $2,433,347 on an interim basis by means of class-specific rate riders and manual adjustments, effective May 1, 2021 to April 30, 2023, as identified in Section 9.3 of Exhibit 9
13	b	Approval for the clearance of the balances recorded in certain Group 2 deferral and variance accounts of $2,708,451 by means of class-specific rate riders effective from May 1, 2021 to April 30, 2023 as follows
13	b. i.	Approval for the clearance of the balance in its Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”) of $1,039,196, resulting from its Conservation and Demand Management (“CDM”) activities up to December 31, 2020 as identified Section 4.6.2 of Exhibit 4
13	b. ii.	Approval for the clearance of the balance in its USoA Account 1575 - IFRS-CGAP Transitional PP&E Amounts of $829,462, resulting from BHI’s transition to IFRS by means of class-specific rate riders effective from May 1, 2021 to April 30, 2023, as identified in Section 9.1 of Exhibit 9
13	c	Approval of the continuation of certain deferral and variance accounts, as set out in Section 9.0.5 of Exhibit 9
13	d	Approval of discontinuation of certain deferral and variance accounts, as set out in Section 9.0.5 of Exhibit 9
14		Approval to make its current (i.e., 2020) rates provided in Appendix B of Exhibit 8 interim effective May 1, 2021, if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2021
15		Approval to establish an account to recover any differences between the interim rates and the actual rates effective May 1, 2021 if the preceding approvals cannot be issued by the OEB in time to implement final rates effective May 1, 2021
16		Approval of other items or amounts that may be requested by BHI in the course of the proceeding, and such other relief or entitlements that the OEB may grant

1.5 DISTRIBUTION SYSTEM OVERVIEW

BHI is a local distribution company serving approximately 68,000 residential and commercial customers in the City of Burlington. It operates under distribution licence [ED-2003-0004] and maintains 32 Municipal Substations ("MS") and almost 1,600 kilometers of distribution lines throughout its service area. The company is wholly owned by the City and the boundaries of the service area are:

- West:
  - Hwy. 6 (North Shore Blvd. to Old York Rd.)
  - Snake Rd. (Old York Rd. to Main St. S.)
  - Mountainbrow Rd. to Kerns Rd.
  - Kerns Rd. / Parkside Dr. / Millborough Townline (Mountainbrow Rd. to Derry Rd.)
- North:
  - Plains Rd. to Snake Rd. to Mountainbrow Rd. to King Rd. ending at Kerns Rd.
  - Derry Rd. (Millborough Townline to Bell School Line)
  - 1 Side Rd. (Bell School Line to Tremaine Rd.)
- East:
  - Bell School Line (Derry Rd. to 1 Side Rd.)
  - Tremaine Rd. / Burloak Dr. (1 Side Rd. to Lakeshore Rd.)
- South:
  - The shore of Lake Ontario

BHI's total service area is 188 square km, of which 90 square km are rural and the remainder is urban. Geographically, Burlington is located in Halton Region between the north shore of Lake Ontario and the Niagara Escarpment. Economically, Burlington is located near the geographic center of the Golden Horseshoe, a densely populated and industrialized region home to over 7,000,000 people. Part of the surrounding semi-rural area is included in the Ontario government's Greenbelt Plan Area. BHI's service area is illustrated in Figure 6.

Figure 6 – Map of BHI's Service Area

BHI is responsible for providing all regulated distribution services within its service area. Its distribution system has an almost even split of overhead to underground infrastructure, with 56% of its service area served by overhead infrastructure and 44% served by underground infrastructure.

BHI does not have any other LDCs embedded within its distribution system and it is not a host utility to other distributors. BHI's neighbouring electricity distribution utilities are:

- Alectra Utilities to the West;
- Milton Hydro to the North;
- Hydro One Networks to the Northeast; and
- Oakville Hydro to the East.

BHI's distribution system is supplied by Hydro One Networks Inc. ("HONI") from five Transformer Stations ("TSs"), namely Burlington TS, Cumberland TS, Bronte TS, Palermo TS and Tremaine TS. All TSs are owned and operated by HONI, up to and including the feeder breakers. BHI does not own or operate assets that operate at voltages greater than 50 kV. BHI owns 34 distribution feeders egressing from the TS, all of which operate at 27.6 kV. Distribution transformers on the 27.6-kV system supply customers directly.

BHI does not have any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets and is not asking the OEB to deem any transmission or high voltage assets as distribution assets in this Application.

1.6 APPLICATION SUMMARY

BHI provides a summary of the key elements of its Application in Table 7 below. The proposed changes in the Application which will have an impact on all customers are Operating, Maintenance and Administration (OM&A) Expenses; depreciation expense driven by an increase in capital expenditures; and the disposition of BHI's Group 1 and Group 2 deferral and variance accounts. BHI's net fixed assets have increased since its last rebasing application (EB-2013-0115); however the resulting increase in rate base (and as a result the increase in return on equity and debt), has been mitigated by (i) a reduction in the default Working Capital Allowance from 13% to 7.5%[33]; and (ii) a reduction in the OEB's Cost of Capital Parameters[34] as compared to 2014. These changes are discussed in further detail below.

Table 7 – Key Elements of the Application

Description	Proposed 2021 Test Year
Revenue Requirement	
Service Revenue Requirement	$37,220,971
Revenue Offsets (Other Operating Revenue)	($1,691,087)
Base Revenue Requirement	$35,529,884
Revenue (Deficiency)/Sufficiency	($3,903,311)
Rate Base	$148,576,805
Capital Expenditures	$13,147,184
Net Fixed Assets	$132,580,500
OM&A	$21,497,775
Depreciation	$6,883,779

1.6 A. Revenue Requirement

BHI's proposed service requirement for the 2021 Test Year is $37,220,971 as identified in Table 8 below. This represents an increase of $6,384,424 or 20.7% as compared to the most recent OEB-approved service revenue requirement.

[33] OEB Letter, *Allowance for Working Capital for Electricity Distribution Rate Applications,* June 3, 2015
[34] https://www.oeb.ca/industry/rules-codes-and-requirements/cost-capital-parameter-updates

Table 8 – Increase/(Decrease) in Revenue Requirement vs. 2014 Cost of Service

Description	2014 Cost of Service (Revised CGAAP)	2014 Cost of Service (MIFRS)	Proposed 2021 Test Year	$ Increase/ (Decrease) (MIFRS)	% Increase/ (Decrease) (MIFRS)	CAGR % Increase/ (Decrease) (MIFRS)
OM&A Expenses	$17,687,000	$17,302,974	$21,497,775	$4,194,801	24.2%	3.1%
Depreciation Expense	$4,126,034	$4,510,060	$6,883,779	$2,373,719	52.6%	6.2%
Property Taxes	$273,559	$273,559	$341,790	$68,231	24.9%	3.2%
Payment in Lieu of Taxes (PILs)	$211,146	$211,146	$457,175	$246,029	116.5%	11.7%
Deemed Interest Expense	$3,603,142	$3,603,142	$2,976,954	($626,188)	(17.4%)	(2.7%)
Return on Deemed Equity	$4,935,666	$4,935,666	$5,063,498	$127,832	2.6%	0.4%
Total Service Revenue Requirement	**$30,836,547**	**$30,836,547**	**$37,220,971**	**$6,384,424**	**20.7%**	**2.7%**
Other Operating Revenue	($2,001,014)	($2,001,014)	($1,691,087)	$309,927	(15.5%)	(2.4%)
Total Base Revenue Requirement	**$28,835,533**	**$28,835,533**	**$35,529,884**	**$6,694,351**	**23.2%**	**3.0%**

The main drivers of this increase are OM&A expenses and depreciation. As identified above, the increase in rate base was offset by a reduction in the OEB's Cost of Capital Parameters for long term debt and equity.

OM&A has increased $4,194,801, or 3.1% per annum on average, as compared to the 2014 OEB-approved amount. Inflation accounts for over 50% of this increase. The remainder is a result of an increase in salaries and benefits; and changes in BHI's operations since 2014. These are discussed in further detail in Section 1.6 E below.

Depreciation has increased $2,373,719, or 6.2% per annum on average, as compared to the 2014 OEB-approved amount. This is driven by an increase in average net fixed assets of $27,828,061 as a result of capital additions over the 2014 to 2021 period. This increase is due to mandatory System Access investments; replacement of end of life distribution infrastructure; and investments in the general plant category to replace legacy computer systems such as BHI's CIS, GIS, Payroll and Human Resources Information System ("HRIS") and Outage Management System ("OMS").

1.6 B. Budgeting and Accounting Assumptions

1.6 B.1 Economic Overview

The City of Burlington is an area of moderate economic growth, with a fixed urban boundary and a limited supply of land designated for warehouse, manufacturing, and office use. The Ontario government's long-term Places to Grow infrastructure plan has provided an expansion impetus, envisaging the City of Burlington as one of the 25 "Urban Growth Centres" in the Greater

Golden Horseshoe. However, the availability of land for residential and commercial expansion is becoming progressively limited as the City of Burlington expands towards the boundary imposed by the Greenbelt, which occupies a large part of its service area, The City of Burlington has responded to the government directive by intensifying vertical development and refurbishment in the downtown core.

Prior to COVID-19, BHI expected low peak demand growth (1%) over the forecast period, which was in alignment with currently available growth forecasts from the Halton Region Official Plan, included as Appendix 2 of the DSP. However, COVID-19 has had a material impact on consumption and demand in the 2020 Bridge and 2021 Years as identified in Section 1.6 C. below.

1.6 B.2 Accounting Standard

BHI adopted new capitalization and depreciation policies under revised CGAAP effective January 1, 2013 as directed by the OEB.[35] These policies incorporated changes to the useful lives of its capital assets and changes to its capitalization polices with respect to overheads. BHI's last rebasing application (EB-2013-0115) was filed on a Revised CGAAP basis. BHI transitioned to IFRS as of January 1, 2015 and has prepared this Application on a MIFRS basis for the 2014-2019 Actuals, the 2020 Bridge Year and the 2021 Test Year. There were no material changes between the 2014 Revised CGAAP and MIFRS statements with the exception of $396,790 in depreciation allocated to OM&A under revised CGAAP and to depreciation expense under MIFRS. This change is discussed in further detail in Section 1.4.12 of this Exhibit 1.

1.6 B.3 Budgeting Assumptions

BHI prepares an annual budget and 10-year plan that is reviewed and approved by its Board of Directors. The 10-year plan provides a long-term outlook of BHI's financial position and the implications to its stakeholders. The 2021 Test Year budget and 2021-2025 capital expenditures underpinning this Application were approved by BHI's Board of Directors on September 21, 2020.

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[35] OEB Letter: *Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*, July 17, 2012

BHI has used an inflation rate of 2% on non-labour expenditures in the 2021 Test Year, only in the circumstances where the dollar amount of the forecast expenditure was unknown. The inflation rate is equal to the most recent Input Price Index published by the OEB[36]. BHI provides the labour inflation rates used in this Application in Section 4.3.1.2 of Exhibit 4.

1.6 C. Load Forecast Summary

BHI's forecasted energy consumption and demand are expected to decrease as compared to the 2014 OEB-approved load forecast as follows:

- Forecasted energy sales for the 2021 Test Year are 1,530,341,252 kWh which represents a decrease of (108,797,281) kWh or (6.6%) as compared to the 2014 OEB-approved kWh forecast; and
- Forecasted energy demand (GS>50 kW and Street lighting customers) for the 2021 Test Year is 2,283,473 kW which represents a decrease of (198,225) kW or (8%) as compared to the 2014 OEB-approved kW forecast.

BHI's forecasted customer/connection count for the 2021 Test Year is 86,461 which represents an increase of 4,479 customers/connections or 5.5% as compared to the 2014 OEB-approved kWh forecast. Customer/connection counts are based on the average for the year.

Table 9 to Table 11 below provide a high-level summary of BHI's load forecast for the 2021 Test Year as compared to the 2014 OEB-approved forecast.

The delivery of conservation and demand management programs and COVID-19 have had a significant impact on BHI's load from 2014 to 2019 and continue to impact its 2021 load forecast.

1.6 C.1 Impact of Conservation and Demand Management

The implementation of the 2015-2020 Conservation First Framework ("CFF"), with the objective of promoting a culture of conservation in Ontario, and as directed by the provincial government has had a material impact on BHI's actual and forecasted load from 2014 to 2021. The CFF

[36] Ontario Energy Board updates for 2020 EDR applications, October 31, 2019

required the Independent Electricity System Operator ("IESO)" to coordinate, support and fund the delivery of Conservation and Demand Management ("CDM") programs through LDCs to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020. LDCs could deliver their CDM obligations through use of IESO province-wide programs and/or their own, or regional, programs (both of which were IESO funded); and were permitted to do so individually or in a joint plan with one or more LDCs. BHI entered into a Joint CDM Plan with Milton Hydro and Halton Hills Hydro and contracted to deliver 99.04 net GWh in total energy savings over the CFF. BHI was passionate about creating a "culture of conservation" in its community and delivered a diverse portfolio of conservation programs to its customers and up to the end of 2019 had delivered 95 net GWh of savings.

On March 21, 2019, the Minister of Energy, Northern Development and Mines ("MENDM") introduced Bill 87 – Fixing the Hydro Mess Act, which, among other regulatory initiatives, refocused and uploaded electricity conservation programs to the IESO. The Minister issued a Ministerial Directive terminating the CFF and the Energy Conservation Agreements (ECAs) with LDCs. Upon termination of the CFF, the IESO was directed to provide centralized delivery of a reduced scope of programs under an Interim Framework. Under the Interim Framework, the new province-wide target for CDM savings was 1.4 TWh and the framework was scheduled to expire on December 31, 2020.

On September 30, 2020, the MENDM directed the IESO to implement a 2021-2024 CDM Framework launching January 1, 2021. The new framework will be centrally-delivered by the IESO under the Save on Energy brand and will include incentive programs targeted to those who need them most, including opportunities for commercial, industrial, institutional, on-reserve First Nations, and income-eligible electricity consumers.[37] The implications of this new framework have not been contemplated in this Application or the load forecast.

Although the CFF was terminated by the IESO and replaced with an interim framework, the IESO continues to offer programs to customers, specifically Retrofit, Small Business Lighting, Process and Systems Upgrade Program, Home Assistance Program, Local Indigenous Programs; and the Energy Performance Program. These programs continue to generate

[37] http://www.ieso.ca/en/Corporate-IESO/Ministerial-Directives (September 30, 2020)

energy savings in addition to the persistence of energy and demand savings from previously implemented CDM programs.

The success of these programs has resulted in a material decrease in load since 2014 for all rate classes including street lighting. Street light consumption and demand has decreased significantly since 2014 as a result of a series of projects in 2017 and 2018 implemented by the City of Burlington under the CFF. These projects involved converting street light bulbs to a more energy efficient Light Emitting Diode ("LED") technology. This program is discussed in more detail in Section 4.6.2 of Exhibit 4.

1.6 C.2 Impact of COVID-19

COVID-19, described in Section 1.2.7 of this Exhibit 1 has had a material impact on Residential, GS<50 kW and GS>50 kW consumption and demand in the 2020 Bridge and 2021 Test Years.

Residential consumption is expected to increase by 26GWh, from 520GWh in 2019 to 546GWh in 2020, due to a significant shift in the number of employees working from home as compared to 2019. Small commercial consumption is expected to decrease by (17GWh), from 171GWh in 2019 to 153GWh in 2020; and large commercial demand is expected to decrease by 265MW over the same time period; both due to government mandated shutdowns and the negative economic impact of COVID-19. The ongoing impacts of COVID-19 are expected to continue into the 2021 Test Year. BHI expects employees to continue to work from home in the 2021 Test Year, but less so than in the 2020 Bridge Year.

Commercial consumption and demand are not expected to return to pre COVID-19 levels due to shutdowns and reduced operating hours. Total consumption and demand (GS>50 kW and street lighting) in the 2021 Test year is expected to be 1,530GWh and 5,371MW respectively, an increase as compared to the 2020 Bridge Year but still materially lower than the 2019 Actuals. Commercial consumption and demand also declined from the 2014 Test Year to 2019, prior to the impacts of COVID-19, on an actual and weather-normalized basis.

BHI 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.

1.6 C.3 Net Impact to Load Forecast

Residential consumption has declined by (4.4%) as compared to the 2014 OEB-approved Cost of Service due to the following: (i) the 2014 OEB-approved consumption was 1.7% higher than the weather-normalized actuals as identified in Table 12 below; (ii) the success of CDM programs; and (iii) an increase in the number of customers working from home as compared to pre-COVID periods. However, distribution revenue for the residential rate class is unaffected by consumption as a result of the transition to fully fixed distribution rates effective May 1, 2019. As such, the lost revenue associated with a reduction in load for small and large commercial customers is not offset by the increase in residential consumption and will be recovered in this Application from those rate classes paying a combination of fixed and variable rates.

Small commercial consumption and large commercial demand has declined by (3.9%) and (7.5%) respectively as compared the OEB-approved amounts, as identified in Table 9 and Table 10 respectively. This is a result of (i) the 2014 OEB-approved consumption was 0.3% and 2.6% higher than the weather-normalized actuals as identified in Table 12 below; (ii) the negative impact of COVID-19; and (iii) the success of CDM programs.

The street lighting class is unaffected by the weather or COVID-19. The driver of the decrease in consumption and demand is (i) OEB-approved consumption was 9.5% higher than the 2014 actuals as identified in Table 12 below; and (ii) decrease in demand and consumption as a result of the LED conversion program conducted by the City of Burlington in 2017 and 2018.

Table 9 – Consumption Forecast (kWh)

Rate Class	Consumption (kWh)					
	2014 Cost of Service	2019 Weather Normal Actuals	2020 Bridge Year	2021 Test Year	Incr/(Decr) 2021 vs. 2014 CoS kWh	Incr/(Decr) vs. 2014 CoS %
Residential	553,858,289	520,074,034	546,039,497	529,231,270	(24,627,019)	(4.4%)
GS<50 kW	173,842,956	170,772,378	152,883,777	167,003,174	(6,839,782)	(3.9%)
GS>50 kW	897,316,673	852,880,237	744,818,692	825,433,794	(71,882,879)	(8.0%)
Street Lights	10,968,788	5,537,653	5,541,714	5,569,644	(5,399,144)	(49.2%)
USL	3,151,827	3,144,191	3,128,398	3,103,371	(48,456)	(1.5%)
Total	**1,639,138,533**	**1,552,408,493**	**1,452,412,078**	**1,530,341,252**	**(108,797,281)**	**(6.6%)**

Table 10 – Demand Forecast (kW)

Rate Class	Demand (kW)					
	2014 Cost of Service	2019 Weather Normal Actuals	2020 Bridge Year	2021 Test Year	Incr/(Decr) 2021 vs. 2014 CoS kW	Incr/(Decr) vs. 2014 CoS %
GS>50 kW	2,451,173	2,309,173	2,031,467	2,267,945	(183,228)	(7.5%)
Street Lights	30,525	15,446	15,448	15,528	(14,997)	(49.1%)
Total	**2,481,698**	**2,324,619**	**2,046,915**	**2,283,473**	**(198,225)**	**(8.0%)**

Table 11 – Customer/Connection Forecast

Rate Class	Customers/Connections					
	2014 Cost of Service	2019 Actuals	2020 Bridge Year	2021 Test Year	Incr/(Decr) 2021 vs. 2014 CoS kW	Incr/(Decr) vs. 2014 CoS %
Residential	59,869	61,428	61,651	62,056	2,187	3.7%
GS<50 kW	5,224	5,490	5,506	5,564	340	6.5%
GS>50 kW	1,012	985	1,004	1,003	(9)	(0.9%)
Street Lights	15,272	17,184	17,197	17,283	2,011	13.2%
USL	605	562	559	554	(51)	(8.4%)
Total	**81,982**	**85,648**	**85,916**	**86,461**	**4,479**	**5.5%**

Table 12 – kWh and kW Comparison 2014 Weather Normalized Actuals vs. OEB-approved

Rate Class	Billing Determinant	2014 Cost of Service	2014 Actuals (Weather Normal)	Increase/ (Decrease)	Increase/ (Decrease) %
Residential	kWh	553,858,289	544,629,928	(9,228,361)	(1.7%)
GS<50 kW	kWh	173,842,956	173,351,271	(491,685)	(0.3%)
GS>50 kW	kW	2,451,173	2,387,587	(63,586)	(2.6%)
Street Lights	kW	30,525	27,636	(2,889)	(9.5%)
Unmetered Scattered Load	kWh	3,151,827	3,098,633	(53,194)	(1.7%)

1.6 C.4 Load Forecast Methodology

BHI used a multivariate regression model, consistent with its last rebasing application, to determine a class specific, weather-normalized load forecast and customer/connection forecast for the 2021 Test Year. This forecast incorporates historical and forecasted CDM impacts.

1.6 D. Rate Base and DSP

1.6 D.1 Major Drivers of the DSP

BHI's DSP, filed as Appendix A in Exhibit 2, was developed to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives. BHI's investment plans are the outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. The major drivers of the level and mix of capital investment in the DSP are as follows and discussed in further detail in Section 1.2.6:

- Deteriorating Condition of Distribution Infrastructure
- Adverse Weather Events
- City Growth and Capacity Constraints
- Business Operations Continuity

1.6 D.2 Rate Base Summary

BHI's proposed rate base in the 2021 Test Year is $148,576,805, which is $27,828,061 or 13% higher than the 2014 OEB-approved rate base of $131,828,683 as identified in Table 13 below.

Table 13 – 2021 Test Year vs. 2014 OEB Approved Rate Base

Description	2014 CoS (EB-2013-0115)	2021 Test Year	Variance $ Incr/(Decr)	Variance % Incr/(Decr)
Net Fixed Assets				
Gross Fixed Assets (Average)	$246,120,360	$309,790,789	$63,670,430	25.9%
Accumulated Depreciation (Average)	$141,367,920	$177,210,289	$35,842,369	25.4%
Net Fixed Assets (Average)	**$104,752,440**	**$132,580,500**	**$27,828,061**	**26.6%**
Allowance for Working Capital				
Cost of Power	$190,702,260	$191,444,505	$742,245	0.4%
Distribution Expenses	$17,576,533	$21,839,565	$4,263,032	24.3%
Total CoP/Distribution Expenses	**$208,278,793**	**$213,284,070**	**$5,005,277**	**2.4%**
Working Capital Allowance %	13.0%	7.5%		
Working Capital Allowance	**$27,076,243**	**$15,996,305**	**($11,079,938)**	**(40.9%)**
Rate Base				
Total Rate Base	**$131,828,683**	**$148,576,805**	**$16,748,123**	**12.7%**

The increase in rate base from the 2014 OEB-approved amount to the 2021 Test Year is due to an increase in average net fixed assets of $27,828,061, partially offset by a decrease in the Working Capital Allowance ("WCA") of ($11,079,938).

The increase in net fixed assets is primarily a result of capital additions over the 2014 to 2019 period. Approximately half of BHI's capital additions over the period were mandatory System Access investments. BHI invested in replacing end of life assets such as wood poles, underground primary cable, distribution transformers and MS assets in order maintain system reliability and mitigate the risk of unplanned outages due to asset failure. BHI also invested in feeder egress cables from the Tremaine TS to accommodate growth in North East Burlington; and made a number of one-time investments to replace legacy information systems in support of improved customer service and business process efficiency.

The reduction in WCA of ($11,079,938) is primarily a result of the decrease in the default WCA rate from 13% to 7.5% as mandated by the OEB.[38]

1.6 D.3 Capital Expenditure Summary

BHI's proposed capital expenditures in the 2021 Test Year are $13,147,183, which is $5,417,138 or 70% higher than the 2014 OEB-approved capital expenditures of $7,730,045 as identified in Table 14 below.

Table 14 – 2021 Test Year vs. 2014 OEB Approved Capital Expenditures

Description	2014 CoS (EB-2013-0115)	2021 Test Year	Variance $ Incr(Decr)	Variance % Incr/(Decr)
System Access	$8,244,469	$28,316,438	$20,071,969	243.5%
System Renewal	$1,349,241	$2,960,000	$1,610,759	119.4%
System Service	$908,540	$375,000	($533,540)	(58.7%)
General Plant	$807,000	$1,552,000	$745,000	92.3%
Gross Expenditures	**$11,309,250**	**$33,203,438**	**$21,894,188**	**193.6%**
Capital Contributions	($3,579,205)	($20,056,254)	($16,477,049)	460.4%
Net Capital Expenditures	**$7,730,045**	**$13,147,183**	**$5,417,138**	**70.1%**

[38] OEB Letter, *Allowance for Working Capital for Electricity Distribution Rate Applications,* June 3, 2015

The increase in capital expenditures from the 2014 OEB-approved amount to the 2021 Test Year is primarily driven by mandatory System Access expenditures, including significant third-party infrastructure projects such as the Dundas St. Road Widening program, the Waterdown Rd. Road Widening program, the Metrolinx GO Corridor Electrification project, the Burloak Grade Separation project and the Fairview Street relocation project.

System Renewal expenditures in the 2021 Test Year are driven by increased renewal of assets in Very Poor or Poor condition, based on the results of BHI's ACA. This includes establishing new programs to proactively replace station switchgear and MS feeder cables to avoid failures and mitigate the backlog of replacements in the future.

These increases are partially offset by lower System Service expenditures in the 2021 Test Year as compared to the 2014 OEB-approved amount; driven by lower expenditures on feeder egress construction from the Tremaine TS. The Tremaine TS was constructed by HONI and energized in 2013 – BHI constructed feeder egress cables in 2014 and 2015 in order to extract the required load from the station. The next phase of work is expected to commence in 2022.

Higher General Plant expenditures in the 2021 Test Year as compared to the 2014 OEB-approved amount are driven by the replacement of BHI's end-of-life standby generator and the replacement of one of its heavy-duty trucks.

1.6 D.4 Renewable Energy Connections

BHI forecasts that there will be ten connections during 2021 to 2025 based on applications currently being processed and those expected to be received as part of the Net Metering Program. BHI has available capacity for Renewable Energy Generation ("REG") connections at several feeders. It is not proposing any investments over the forecast period of its DSP to facilitate REG connections.

1.6 E. Operations, Maintenance and Administration Expense

1.6 E.1 Total OM&A

BHI is proposing recovery through distribution rates of $21,497,775, which represents an increase of $4,194,801 or 3.1% per annum on average as compared to the 2014 OEB-approved amount (MIFRS), as identified in Table 15 below.

Table 15 – OM&A 2021 Test Year vs. 2014 OEB-approved (MIFRS)

Description	2014 OEB-approved (Revised CGAAP)	2014 OEB-approved (MIFRS)	2021 Test Year (MIFRS)	2021 vs. 2014 CoS (MIFRS) Incr/(Decr)	2021 vs. 2014 (MIFRS) OEB approved CAGR
Total OM&A excluding Property Taxes	$17,687,000	$17,302,974	$21,497,775	$4,194,801	3.1%

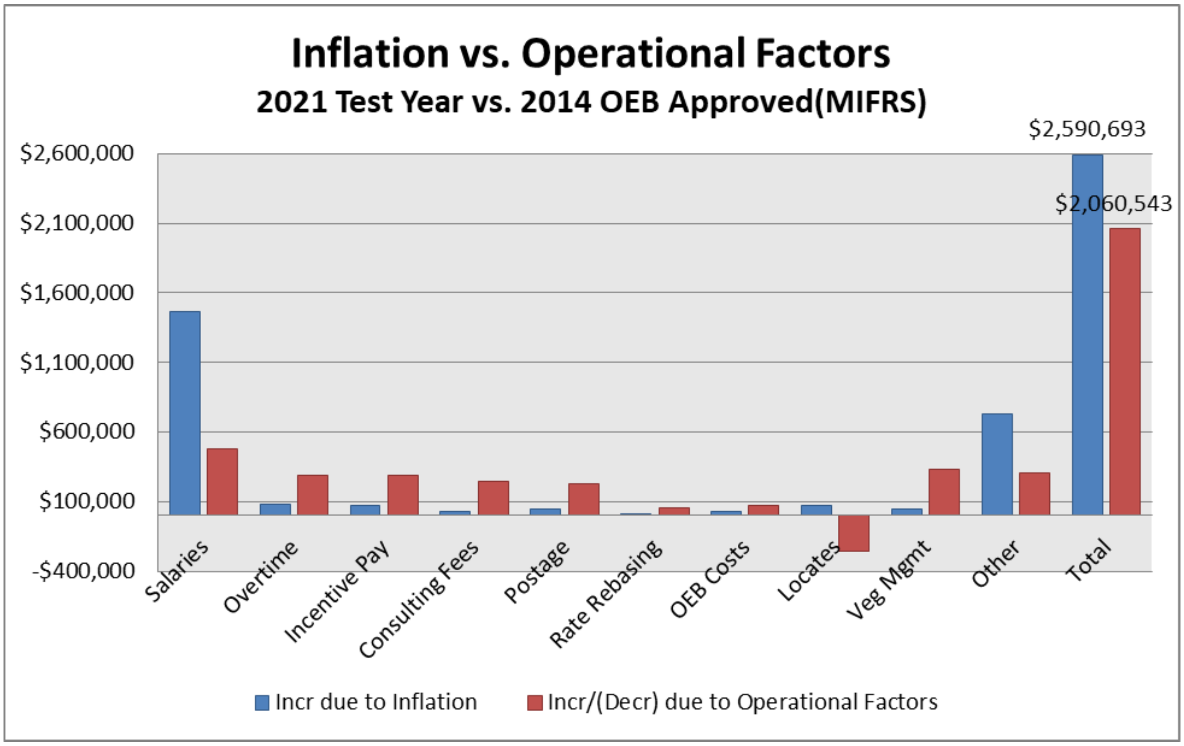
This represents an increase of $4,651,236 as compared to the 2014 Actuals (MIFRS) of $16,846,540 as identified in Table 16 below.

Table 16 – OM&A 2021 Test Year vs. 2014 Actuals (MIFRS)

Description	2014 OEB-approved (Revised CGAAP)	2014 Actuals (MIFRS)	2021 Test Year (MIFRS)	2021 vs. 2014 CoS (MIFRS) Incr/(Decr)	2021 vs. 2014 (MIFRS) OEB approved CAGR
Total OM&A excluding Property Taxes	$17,687,000	$16,846,540	$21,497,775	$4,651,236	3.5%

Approximately 56% or $2,590K of the $4,651,236 increase is due to inflationary increases, primarily in salaries and benefits and other expenditures, as identified in Figure 7 below. The remaining 44% or $2,060,543 is a result of changes in BHI's operations, some of which are outside of its control as discussed in Section 1.6 E.2 below.

Figure 7 – Inflation vs. Operational Factors



1.6 E.2 Summary of Overall Drivers and Cost Trends

Total OM&A excluding property taxes for the 2021 Test Year is expected to increase by $2,409,231 as compared to the 2019 Actuals as identified in Table 17 below. This increase is driven by inflation; and a number of policy, business environment, distribution operations and technological changes.

Table 17 – Summary OM&A

Description	2019 Actuals	2020 Bridge Year	2021 Test Year	2021 Test Year vs. 2019 Actuals			% of Total Increase
				Total Incr/(Decr)	Incr/(Decr) Due to Inflation	Incr/(Decr) Due to Operational Factors	
Total Salaries and Benefits [1]	$11,650,860	$11,359,148	$12,361,982	$711,122	$531,025	$180,097	30%
Policy/Business Changes	$720,552	$957,418	$1,363,433	$642,881	$29,110	$613,770	27%
Disitribution Operations Changes	$747,942	$1,106,006	$1,155,502	$407,560	$30,217	$377,343	17%
Technological Changes	$629,190	$1,005,247	$834,269	$205,079	$25,419	$179,660	9%
Other Costs	$5,340,000	$5,334,685	$5,782,590	$442,590	$215,736	$226,854	18%
Sub-Total ex Salaries/Benefits	**$7,437,685**	**$8,403,356**	**$9,135,794**	**$1,698,109**	**$300,482**	**$1,397,626**	**70%**
Total	**$19,088,545**	**$19,762,504**	**$21,497,775**	**$2,409,231**	**$831,508**	**$1,577,723**	**100%**

1. Includes costs of temporary staff

Salaries and benefits are expected to increase by $711,122 as compared to the 2019 actuals. The majority of this increase is attributable to inflation of $531,025. The remaining amount of

$180,097 is attributable to an increase in headcount as compared to 2019 of $453,931, partly offset by a decrease in expenditures related to temporary staffing of ($273,834):

- BHI had nine (9) vacancies at the end of 2019 which it plans to fill by 2021.
- These vacancies are a result of several factors including a high rate of turnover, particularly retirements since 2014; a competitive job market; a job skills shortage; rapid technological change; and increasing regulatory requirements.
- Temporary staff were hired in 2019, over and above historical levels, in order to fulfill the job duties of the vacant positions. As BHI fills vacancies through 2020 and 2021, expenditures are expected to revert to historical levels by the 2021 Test Year which will partially offset the increase in salaries and benefits.

All other costs are expected to increase by $1,698,109 as compared to the 2019 actuals. The majority of this increase is attributable to operational factors of $1,397,626. The remainder is due to inflation of $300,482. The drivers of the costs associated with BHI's operations are as follows:

- An increase in costs of $642,881 (including inflation) associated with policy decisions and changes in the business environment which are primarily outside of BHI's control:
    - Conversion to monthly billing $279,802;
    - Rate rebasing costs $169,769;
    - OEB regulatory costs $93,107;
    - Bad Debt expense $100,203;
- An increase in costs for third party operations and maintenance programs of $407,560 (including inflation) for which BHI investigated alternatives and select the option which provided an appropriate balance between costs and operational risks:
    - Provision of Locates $166,299;
    - Vegetation management $241,261;
- An increase in costs primarily driven by technological changes of $205,079 (including inflation); and
- All other costs of $442,590; approximately 50% of which is due to inflation.

Further details are provided in Exhibit 4.

1.6 E.3 Inflation Rate for OM&A Forecasts

BHI has used an inflation rate of 2% on non-labour expenditures in 2021, only in the circumstances where the dollar amount of the forecast expenditure was unknown. The inflation rate is equal to the most recent Input Price Index published by the OEB.[39] BHI provides the labour inflation rates in Section 4.3.1.2 of Exhibit 4.

1.6 E.4 Total Compensation

BHI total compensation for the test year is $15,828,497, which represents an increase of $3,028,725 relative to 2014, or 3.1% per annum on average, as identified in Table 18 below. Total compensation is discussed in further detail in Exhibit 4.

Table 18 – 2021 Test Year vs. 2014 OEB-approved Total Compensation

Description	2014 OEB-approved	2021 Test Year	2021 vs. 2014 CoS Incr/(Decr)	2021 vs. 2014 CAGR
Total Compensation (Salary, Wages, & Benefits)	$12,799,772	$15,828,497	$3,028,725	3.1%

1.6 F. Cost of Capital

BHI summarizes its proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital ("WACC") in Table 19 below.

Table 19 – Proposed Capital Structure and Cost of Capital Parameters

Description	Capital Structure	Rate of Return
Short Term Debt	4.0%	2.75%
Long Term Debt	56.0%	3.38%
Equity	40.0%	8.52%
Weighted Average Cost of Capital		**5.41%**

BHI is using the OEB's cost of capital methodology for its capital components. BHI's proposed deemed capital structure for the 2021 Test Year is 60% debt (56% long-term debt and 4% short-term debt) and 40% equity. BHI is using the OEB's cost of capital parameters as published on

[39] Ontario Energy Board updates for 2020 EDR applications, October 31, 2019

October 31, 2019.[40] The long term debt rate of 3.38% for the 2021 Test Year used in this Application is the weighted average of the interest on BHI's outstanding long-term debt instruments and forecasted new debt in the 2021 Test Year. This approach is in compliance with the OEB Staff Report *Review of the Cost of Capital for Ontario's Regulated Utilities*[41], issued January 14, 2016.

1.6 G. Cost Allocation and Rate Design

BHI engaged Elenchus Research Associates ("Elenchus") to assist in completing a Cost Allocation Study for the 2021 Test Year using the OEB-approved cost allocation model. BHI did not deviate from the OEB's cost allocation and rate design methodologies.

BHI has made three changes to its cost allocation since its last rebasing application (EB-2013-0115) as follows:

- **Load Profiles**: BHI used the load profiles provided by Hydro One Networks Inc. ("HONI") in its cost allocation model in its last rebasing application. The HONI profiles were based on 2004 data, and consumption patterns have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing. In a letter dated June 12, 2015[42] ("New Cost Allocation Policy Letter"), the OEB stated that it expected distributors to be mindful of material changes to load profiles and to propose updates in their respective cost of service applications when warranted. BHI's Cost Allocation model in this Application incorporates updated load profiles for all rate classes. This has had an impact on proposed Revenue to Cost ("R-C") ratios.

- **New Cost Allocation Policy for the Street Lighting Rate Class**: In the same New Cost Allocation Policy Letter, the OEB outlined a new cost allocation policy for the street lighting rate class. A new "street lighting adjustment factor" ("SLAF") is to be used to allocate costs to the street lighting rate class for primary and line transformer assets. The SLAF replaced the "number of connections" allocator. The OEB updated their cost

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[40] https://www.oeb.ca/industry/rules-codes-and-requirements/cost-capital-parameter-updates
[41] EB-2009-0084, Table 1: Current Cost of Capital Methodology, p 3
[42] EB-2012-0083, *Review of Cost Allocation Policy for Unmetered Loads, Issuance of New Cost Allocation Policy for Street Lighting Rate Class*

allocation model dated to incorporate the SLAF. BHI implemented these changes in its cost allocation model for this Application - the SLAF reduced the share of primary and line transformer costs that was attributed to Street lighting customers.

- **<u>Rate Design for Residential Electricity Customers</u>**: On April 2, 2015, the OEB released its Board Policy: *A New Distribution Rate Design for Residential Electricity Customers* (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers over a four-year transition period commencing in 2016 and ending in 2019. BHI completed the transition to fully-fixed rates for residential customers on May 1, 2019.

In addition to the aforementioned policy changes, the conversion of street lights to LED technology in 2017 and 2018, as explained in Section 1.6 C.1, had a significant impact on peak demand. Peak demand declined as lights were replaced with lower energy-consuming LEDs; and consequently revenues and costs were impacted. Lower peak demand resulted in:

- Lower variable distribution revenues – approximately 35% of distribution revenue is attributable to variable distribution revenue - the street lighting class is billed on kW; and
- A decline in costs allocated to the street lighting class.

BHI provides a comparison of its proposed Revenue to Cost ("R-C") ratios in this Application to the 2014 Board approved R-C ratios in Table 20 below.

Table 20 – Revenue to Cost Ratios Comparison

Rate Class	Revenue to Cost Ratios			
	2014 Cost of Service	Status Quo	2021 Test Tear	Policy Range
Residential	105.00%	100.80%	100.80%	85-115%
GS<50 kW	100.00%	108.85%	108.85%	80-120%
GS>50 kW	89.41%	92.19%	93.25%	80-120%
Street Lighting	95.96%	154.24%	120.00%	80-120%
Unmetered Scattered Load (USL)	119.96%	180.79%	120.00%	80-120%

The rate classes materially impacted by policy changes and/or conservation programs are Street Lighting and Unmetered Scattered Load ("USL").

The R-C ratio for the street lighting class, after incorporating policy changes and lower demand as a result of the LED conversion was 154.24% as identified in Table 20 above. Although both revenue and costs declined, the impact of these changes resulted in a larger decline in allocated costs than the decline in revenues. In accordance with the OEB's approved cost allocation and rate design methodology, BHI reduced the revenue allocated to the street lighting class such that proposed revenues are 120% of allocated costs, within the OEB-approved range.

The change in the R-C ratio for USL customers is a result of updating the load profiles to represent BHI specific data. The 2004 demand data from HONI used in BHI's previous cost of service applications had significant variations in peak demand during daylight and night hours, similar to the load profile of the Street Lighting class. BHI's experience is that demand is constant for this rate class, which resulted in a reduction in demand and therefore allocation of demand-related costs as compared to the 2014 Cost Allocation model. The R-C ratio for the USL class, after incorporating these changes was 180.79% as identified in Table 20 above. In accordance with the OEB's approved cost allocation and rate design methodology, BHI reduced the revenue allocated to the USL class such that proposed revenues are 120% of allocated costs, within the OEB-approved range.

The adjustment to the R-C ratios for the street lighting and USL classes resulted in a revenue deficiency of $99,635 which BHI allocated to the GS>50 kW rate class – the only rate class whose R-C ratio was under 100%. This resulted in an increase in the R-C ratio from 92.19% in 2021 before any adjustments, to 93.25%; and represented an increase of 3.84% as compared to the 2014 OEB-approved R-C ratio.

BHI provides a comparison of its proposed fixed/variable splits in this Application to the 2014 Board approved fixed/variable splits in Table 21 below. There are two main changes as follows:

- The transition to fully fixed rates effective May 1, 2019 for residential customers results in a fixed/variable split of 100%/0%; and
- The Street Light LED conversion lowered peak demand and consequently variable distribution revenue as compared to 2014. Fixed distribution revenue has increased over that period due to an increase in the number of devices. As such the fixed/variable split has changed from 45%/55% in BHI's last OEB-approved application to 65%/35% in this Application.

Table 21 – Fixed/Variable Split Comparison

Rate Class	Fixed Revenue Proportion			Variable Revenue Proportion		
	2014 OEB-Approved	2020 Bridge Year	2021 Test Year	2014 OEB-Approved	2020 Bridge Year	2021 Test Year
Residential	48.83%	100.00%	100.00%	51.17%	0.00%	0.00%
GS<50 kW	40.18%	42.73%	42.73%	59.82%	57.27%	57.27%
GS>50 kW	9.88%	9.73%	9.81%	90.12%	90.27%	90.19%
Street Lighting	45.15%	64.86%	64.86%	54.85%	35.14%	35.14%
Unmetered Scattered Load (USL)	57.09%	55.23%	55.23%	42.91%	44.77%	44.77%

BHI is not proposing a rate mitigation plan in this Application as there are no rate classes for which the total bill impact exceeds the 10% total bill impact threshold.

1.6 H. Deferral and Variance Accounts

BHI is proposing to dispose of $5,141,798 in its Group 1 and Group 2 Deferral and Variance accounts ("DVAs") as identified in Table 22 below. The amount allocated to Regulated Price Plan ("RPP") and non-RPP customers is also identified.

Table 22 – DVA Disposition

Deferral and Variance Accounts	USoA	Total Proposed for Disposition	RPP Customers	non-RPP Customers
Group 1				
Smart Metering Entity	1551	($10,024)	($9,791)	($233)
RSVA - Wholesale Market Service Charge	1580	($279,667)	($205,038)	($190,841)
RSVA - Wholesale Market Service Charge - CBR B	1580	($116,212)		
RSVA - Retail Transmission Network Charge	1584	$69,498	$35,995	$33,503
RSVA - Retail Transmission Connection Charge	1586	$251,624	$130,324	$121,300
RSVA - Power	1588	$572,229	$296,375	$275,853
RSVA - Global Adjustment	1589	$1,945,901	$0	$1,945,901
Total Group 1 Balances		**$2,433,348**	**$247,865**	**$2,185,483**
Group 2				
Other Regulatory Assets - Deferred IFRS Transition Costs	1508	$328,603	$170,194	$158,409
Other Regulatory Assets - Pole Attachment Charge Revenues Variance	1508	($727,884)	($559,659)	($168,225)
Other Regulatory Assets - Monthly Billing Incremental Costs	1508	$851,260	$440,895	$410,365
Other Regulatory Assets - OEB Cost Assessment Variance	1508	$452,018	$234,114	$217,903
Other Regulatory Assets - Collection Charges Lost Revenue	1508	$280,898	$145,486	$135,412
ICM - Tremaine TS CCRA (Project 1) - Net	1508	($177,855)	($92,117)	($85,738)
ICM - Tremaine TS Breakers (Project 2) - Net	1508	$17,934	$9,289	$8,646
RCVA - Retail Services	1518	($3,617)	($1,873)	($1,744)
RCVA - Services Transaction Requests	1548	$2,598	$1,346	$1,253
Extraordinary Event Costs (Z Factor) - 2018 Wind Storm	1572	$8,391	$4,346	$4,045
PILs & Tax Variance - CCA Changes	1592	($192,554)	($99,730)	($92,824)
Total Group 2 Balances before LRAM/1575		**$839,793**	**$252,291**	**$587,502**
Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	1568	$1,039,196	$402,076	$637,120
Total Group 2 Balances before 1575		**$1,878,988**	**$654,367**	**$1,224,622**
IFRS-CGAAP Transitional PP&E Amounts	1575	$829,462	$429,605	$399,857
Total Group 2 Balances		**$2,708,450**	**$1,083,972**	**$1,624,479**
Total DVA Balances		**$5,141,798**	**$1,331,837**	**$3,809,962**

BHI is proposing a disposition period of two years for its Group 1 and Group 2 accounts – a two year disposition period will mitigate the impact of BHI's proposed rate increase as discussed in Section 1.2.6.7 of this Exhibit 1.

BHI is not requesting to establish any new DVAs. BHI is requesting discontinuation of the DVAs identified in Table 23 below. The rationale for these proposals and further details on BHI's DVAs is provided in Exhibit 9.

Table 23 – Proposed List of DVAs to be Discontinued

Group 2 Account	USoA
Other Regulatory Assets - Deferred IFRS Transition Costs	1508
Other Regulatory Assets - Pole Attachment Charge Revenues Variance	1508
Other Regulatory Assets - OEB Cost Assessment Variance	1508
ICM - Tremaine TS CCRA (Project 1) - Actual Rate Rider	1508
ICM - Tremaine TS Breakers (Project 2) - Actual Rate Rider	1508
RCVA - Retail Services	1518
RCVA - Services Transaction Requests	1548
Extraordinary Event Costs (Z Factor) - 2018 Wind Storm	1572
IFRS-CGAAP Transitional PP&E Amounts	1575

1.6 I. Bill Impacts

BHI provides a summary of the bill impacts for typical customers in all customer classes in Table 24 below.

In developing its capital budget for the 2021-2025 rate period, BHI was careful to prioritize and pace capital expenditures at a graduated pace. Additionally it has realized efficiencies and made improvements in its business operations - as identified in Section 4.1.1.12 of Exhibit 4 - in order to moderate customer rate growth.

In order to mitigate the bill impact of the distribution rate increase in the 2021 test year, BHI is proposing to dispose of its Group 1 and Group 2 Deferral and Variance accounts over a two year period. Disposition of the Group 1 and Group 2 Deferral and Variance is discussed in further detail in Exhibit 9.

Table 24 – Summary of Bill Impacts

Class	kWh	kW	Distribution (Fixed and Volumetric) Sub-Total A			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$27.31	$30.03	$2.73	10.0%
GS<50 kW	2000		$59.39	$65.60	$6.21	10.5%
GS>50 kW	36700	200	$725.38	$819.75	$94.37	13.0%
Street Lighting	175	0.22	$1.42	$1.85	$0.43	30.2%
Unmetered Scattered Load	2000		$33.25	$25.80	($7.45)	(22.4%)

Class	kWh	kW	Distribution (including pass-through) Sub-Total B			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$30.77	$34.40	$3.64	11.8%
GS<50 kW	2000		$67.88	$77.32	$9.44	13.9%
GS>50 kW	36700	200	$721.72	$927.41	$205.69	28.5%
Street Lighting	175	0.22	$2.32	$2.92	$0.61	26.2%
Unmetered Scattered Load	2000		$41.17	$36.95	($4.22)	(10.3%)

Class	kWh	kW	Total Bill (after HST and OER)			
			Current Rates	Proposed Rates	$ Change	% Impact
Residential	750		$114.56	$117.02	$2.46	2.1%
GS<50 kW	2000		$291.97	$298.31	$6.34	2.2%
GS>50 kW	36700	200	$5,719.86	$5,956.55	$236.68	4.1%
Street Lighting	175	0.22	$26.51	$27.13	$0.63	2.4%
Unmetered Scattered Load	2000		$270.28	$265.53	($4.75)	(1.8%)

1.7 CUSTOMER ENGAGEMENT

1.7.1 Overview

BHI takes its responsibility of informing, gathering feedback and responding to customer needs as a top priority. By engaging in a meaningful way with customers, BHI is better able to meet expectations and provide products/services that enhance the customer experience.

In recent years BHI has embraced new ways to connect with customers – through web-based services, mobile device options, surveys, or by employing social media platforms such as Twitter. A Customer Satisfaction Survey is conducted annually to help identify customer preferences and attitudes about the company. BHI uses that feedback to ensure products and services continue to deliver value customers expect.

The RRFE requires enhanced engagement between distributors and their customers, in order to better align between a distributor's operational plans, and its customers' needs and expectations.

BHI undertook specific customer engagement interactions in 2019 and 2020 to inform customers of (i) the proposals being considered for inclusion in this Application and (ii) the value of those proposals to customers (costs, benefits and bill impacts). BHI retained Innovative Research Group ("IRG") to support its customer engagement outreach and help assess customer needs and preferences with respect to BHI's Distribution System and Business Plans.

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 (more than 7% of its customer base), as summarized in Table 25 below.

Table 25 – Summary of BHI's Customer Engagement Participation

Customer Group	Methodology	Unweighted Sample Size	Field Dates
Residential	Telephone	n=506	June 3 – 25, 2019
Small Business	Telephone	n=116	June 3 – 25, 2019
Residential	Online	n=1,065	June 5 – 21, 2019
Small Business	Online	n=123	June 5 – 21, 2019
Phase I Total Customers Engaged: n=1,810			
Residential	Online Voluntary	n=387	January 16 – February 21, 2020
Small Business	Online Voluntary	n=10	January 16 – February 21, 2020
Residential	Online Representative	n=4,298	January 8 – February 21, 2020
Small Business	Online Representative	n=102	January 8 – February 21, 2020
Commercial (GS > 50 kW)	Online Representative	n=16	December 3 – 18, 2019
Commercial (GS > 50 kW)	In-person Workshop	n=20	January 22, 2020
Phase II Total Customers Engaged: n=4,833			
Total Customers Engaged as Part of Burlington Hydro's Customer Engagement: 6,643			

Customer feedback was gathered via online surveys, telephone surveys, focus groups, and customer workshops. A concerted effort was made to ensure that all customers – regardless of where they live, where they operate, or how much electricity they use – had an equal opportunity to participate, whether through voluntary or random sampling.

1.7.2 Approach

In order to facilitate the collection of feedback, IRG and BHI developed a two-phased approach which was both iterative and responsive at each stage of customer feedback.

The process encompassed a number of steps over the 2-phase approach to ensure a full and inclusive engagement:

1.7.2.1 Phase I

- Step 1: Exploratory Qualitative Research – one night of exploratory focus groups (Residential and GS<50 kW customers)
- Step 2: Parallel Baseline Surveys – concurrent 30 questions online (sent to low-volume customers) - and Telephone Surveys (500 residential and 200 small business customers) and modeling to develop representative customer weights.
- Step 3: Summary Planning, Placement Development – development of customer needs and preferences ‘placemat’ to be used as a planning tool.

1.7.2.2 Phase II

- Step 4: Consultation Narrative Development – development of narrative to be used to form the basis of consultation materials and surveys.
- Step 5: Consultation Narrative ‘Testing’ for Focus Groups – exploratory focus groups (Residential and GS<50 kW)
- Step 6: Residential and GS<50 kW Online Workbook – design, web development, hosting, data collection, analysis, coding and reporting.
    - Residential and GS<50 kW workbook led focus groups
    - Mid-sized and large business workshop
- Step 7: Mid-sized Business Online Survey – design, web development, hosting, data collection, analysis, coding and reporting.
- Step 8: Large Business Online Survey - design, web development, hosting, data collection, analysis, coding and reporting.
- Step 9: Final Customer Engagement Report

Appendix 2-AC of the Chapter 2 OEB Appendices provides a list of customer needs and preferences identified through each engagement activity and the actions taken by BHI to respond.

1.7.3 Customer Engagement Outreach

The “workbook” survey was sent to all residential and small business customers with an email address on file (referred to as the Online Representative survey), as well as promoted through a generic link on the BHI website to any customers who wanted to fill out the workbook survey (referred to as the Voluntary Representative survey). Customers were enticed to participate with an offering of two $500 gift cards available to be won.

Customers were encouraged to complete the workbook in a number of ways:

- A special webpage was created to house the “Your Opinion Matters” customer engagement campaign and a direct link to the Workbook (Figure 8);
- A bill insert was created and included in all electricity bills to promote participation (Figure 9);
- Bill onserts on the face of the bill encouraged customers to participate (Figure 10);
- A promotional display ad published in the Burlington Post on January 30, 2020 (Figure 10); and,
- Participation was encouraged in a series of social media tweets (Figure 10).

Figure 8 – Website Posting

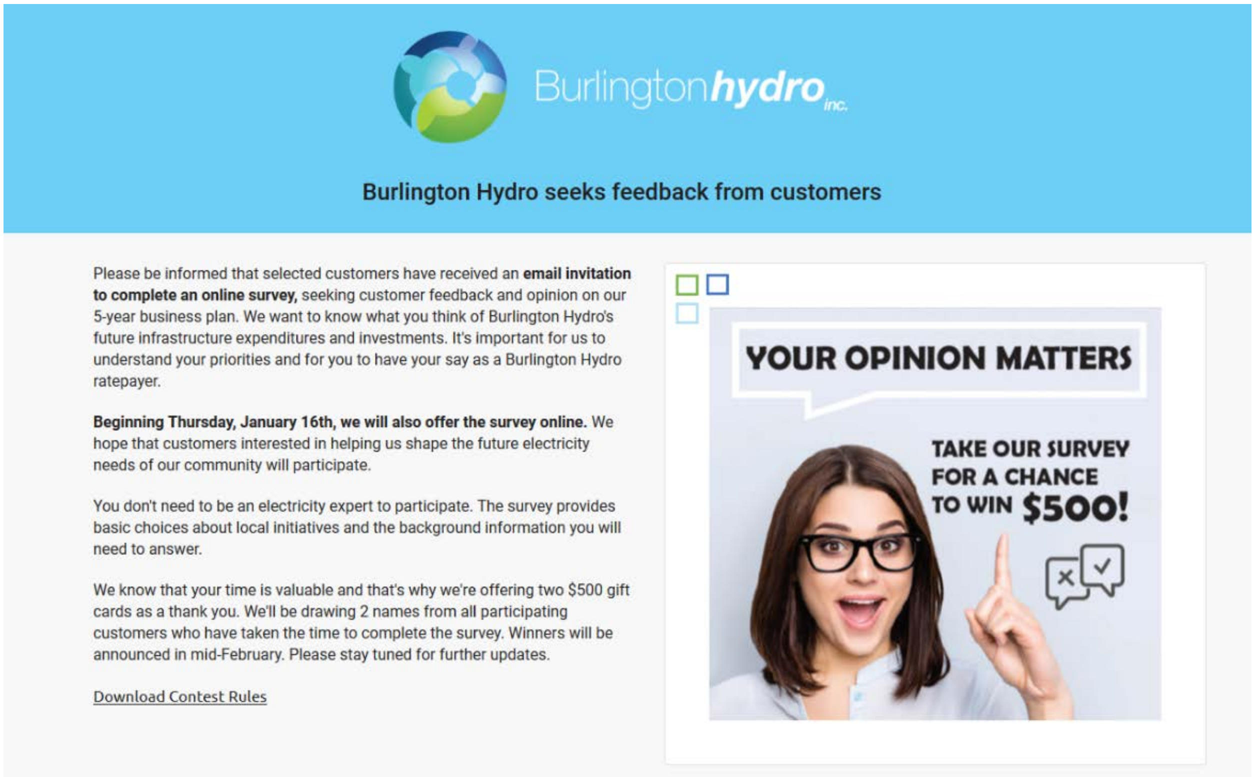


Figure 9 – Bill Insert

Figure 10 – Twitter, Bill Onsert and Display Ad

1.7.4 Phase I Results

Phase I surveys asked if there was **anything that Burlington Hydro could do to improve services**? Overall, it appears that BHI is meeting current customer needs. Table 26 below illustrates the top three mentions as to how BHI could improve service.

Table 26 – How Burlington Hydro Can Improve Service

Summary of Findings Phase I Telephone Results	Residential	Small Business
1st	Nothing (34%)	Nothing (36%)
2nd	Lower/reduce rates (24%)	Lower/reduce rates (28%)
3rd	Reduce outages/better reliability (9%)	Happy with the service (11%)

Among competing outcomes, price, reliability, and finding internal cost efficiencies are the top three priorities for both residential and small business customers. When ranked relative to other priorities, BHI customers see **price as the top outcome that the utility should focus on**, as illustrated in Table 27**.**

Table 27 – Top Priority Outcomes

Summary of Findings Phase I Telephone Results	Residential	Small Business
Top Priority	Reasonable distribution rates	Reasonable distribution rates
2nd Priority	Ensuring reliable electrical service	Ensuring reliable electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

Residential and small business customers have the same **priorities when it comes to reliability**, albeit in a different order. For residential customers, 'restoration times during extreme weather' is number one, while for small business customers it is the number of outages.

Table 28 – Top Priority Reliability Outcomes

Summary of Findings Phase I Telephone Results	Residential	Small Business
1st	Restoration times during extreme weather	Overall number of outages
2nd	Overall length of outages	Restoration times during extreme weather
3rd	Overall number of outages	Overall length of outages

Phase I surveys also explored general **trade-offs between several types of investments and cost.** These questions were intended to provide preliminary input for BHI to put together their initial draft plan. The majority of residential and small business customers are willing to consider paying more to **invest in maintaining reliability**, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Table 29 – Replacing Aging Infrastructure

Replacing Aging Infrastructure Phase I Telephone Results	Residential	Small Business
Invest what it takes to maintain reliability, even if that increases monthly bills	64%	68%
Defer investments to lessen bill impacts, even if it could eventually lead to more or longer power outages	25%	18%

Respondents agree that BHI should make the necessary **investments in equipment and IT systems** that they need to manage the system efficiently and reliably.

Table 30 – Equipment and IT Systems

General Plant Phase I Telephone Results	Residential	Small Business
Make the investments necessary to ensure its staff have the equipment and IT systems they need to manage the system efficiently and reliably	63%	65%
Find ways to make do with the facilities, equipment, vehicles and IT systems it already has	23%	21%

Relative to other investments, **residential customers are least supportive of proactive investments in system capacity.** This is generally aligned with the findings from the initial focus groups, which saw many customers noting that they would like BHI to maintain the status quo.

Table 31 – System Capacity

System Service Phase I Telephone Results	Residential	Small Business
Proactively invest in system capacity	56%	77%
Delay investments in system capacity	31%	18%

When it comes **to proactive investments in modernizing the grid, there is strong support amongst both residential and small business customers**. Customers support these types of investments, knowing that it will cost more now, but could eventually save customers' money down the road.

Table 32 – Grid Modernization

Grid Modernization Phase I Telephone Results	Residential	Small Business
Proactively invest in grid modernization	64%	73%
Make lowest-cost investments	21%	22%

Using the input from the Phase I customer engagement, BHI planners developed a draft plan that included an estimated baseline cost and identified a number of investment areas where pacing could be accelerated, or slowed down, in order to align with customer needs and expectations.

1.7.5 Phase II Results

Overall, a strong majority of BHI customers, in each rate class, support either what is currently included in BHI's draft plan, or an approach that accelerates the pace of investment. When it comes to pacing investments in the underground system, replacing poles in poor condition, and proactively replacing breakers, switchgears, and relays, many customers from each rate class support an accelerated investment approach. These three investments consistently received the strongest levels of support. Across all investments, most customers support an approach that falls somewhere between what is included in the draft plan and a more accelerated pace of investment.

Table 33 – Summary of Phase II Results

Summary of Findings n-size for sample sizes <50	Representative Workbook		Voluntary	GS >50 kW	
	Residential	Small Bus.	Low-Volume	Workbook	Workshop
Improve service	35%	33%	29%	3/16	3/12
Maintain increase (Included in draft plan)	53%	56%	55%	10/16	9/12
Reduce increase	8%	6%	11%	1/16	0/12
Other	2%	1%	2%	0/16	0/12
Don't know	2%	5%	3%	2/16	0/12

Specific attention has been paid to how the opinions of those whose electricity bill has a significant impact on their household (or organization's) finances vary from the broader customer base. Those who agree that their electricity bill has a significant impact on their household finances are less supportive of a plan that spends above the current proposed approach, but still support BHI's draft plan and the associated impacts. The same is true for both residential and small business customers.

Fewer than 1-in-4 residential customers whose electricity bill has a significant impact on their household finances feel that BHI should reduce their level of spending relative to the draft plan.

Table 34 – Phase II Results by Bill Impact on Finances - Residential

Summary of Findings Residential Representative Results	Bill Impact on Finances		
	Significant Impact	Impact	No Impact
Improve service	15%	23%	49%
Maintain increase	52%	63%	46%
Reduce increase	24%	8%	3%

Small business customers whose electricity bill impact's their organization's bottom line are equally as likely to support BHI's draft plan, or an accelerated approach compared to those who noted limited or no impact.

Table 35 – Phase II Results by Bill Impact on Finances - Small Business

Summary of Findings Small Business Representative Results	Bill Impact on Bottomline	
	Impact (Strongly + Somewhat Agree)	No Impact (Strongly + Somewhat Disagree)
Improve service	35%	33%
Maintain increase	52%	56%
Reduce increase	6%	6%

Ultimately, it appears customers believe that BHI has found the right balance between the level of investment proposed in the draft plan, and the associated rate impacts presented. Throughout this engagement, customers consistently noted that they would be supportive of incremental investments to be more proactive in terms of system renewal, and other investments that provide benefit to customers both today and in the future.

1.7.6 Customer Impressions of the Exercise

Nearly all customers who took the time to complete the workbook in its entirety had a favourable impression of the exercise. In addition to strong overall impressions, nearly equal proportions of customers noted that there was “no content missing” nor were they left with any “unanswered questions”. These diagnostics indicate that the Phase II workbook was positively perceived by nearly all customers and covered the information that was expected.

Table 36 – Overall Impression of Workbook

Summary of Findings n-size for sample sizes <50	Representative Workbook		Voluntary	GS >50 kW	
	Residential	Small Bus.	Low-Volume	Workbook	Workshop
Favourable	90%	90%	92%	14/16	11/12
Unfavourable	6%	4%	6%	2/16	0/12

For more details on BHI’s customer engagement activities, refer to Appendix 12 of the DSP.

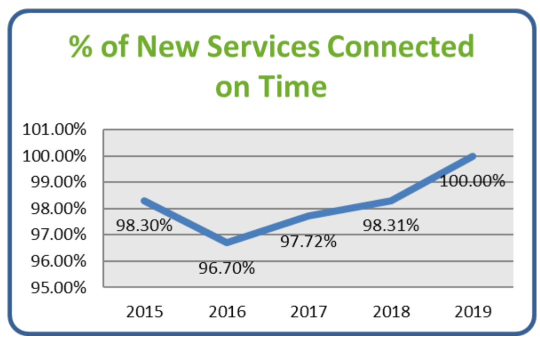
1.8 PERFORMANCE MEASUREMENT

1.8.1 Performance Monitoring and Benchmarking

The OEB expects distributors to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilitate performance monitoring and benchmarking of distributors the OEB uses a scorecard approach. BHI includes its 2019 OEB scorecard as Appendix D in this Exhibit 1. BHI discusses its performance for each of the distributor's scorecard measures over the last five years below, including forward-looking targets it has set for itself in this Application.

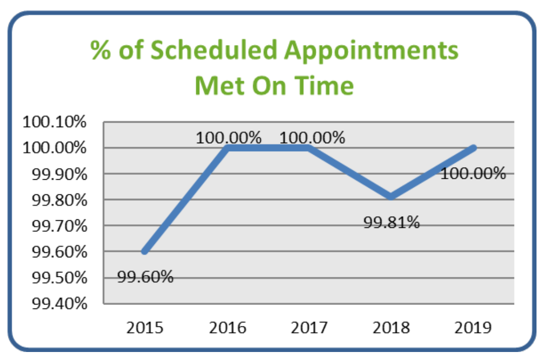
1.8.1.1 New Residential Services Connected on Time

BHI connected new residential and small business services on time over 96% of the time over the 2015-2019 period. BHI field staff manage the day-to-day activities of its field crews to ensure that this service quality measure is met. BHI plans to continue to exceed the OEB target of 90%.



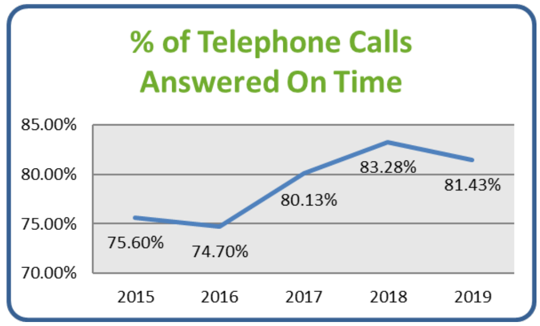
1.8.1.2 Scheduled Appointments Met on Time

BHI met more than 99% of its scheduled appointments on time over the 2015-2019 period. Engineering and construction staff use an electronic calendar to schedule and manage appointments in support of meeting this service quality measure. BHI plans to continue to exceed the OEB target of 90%.



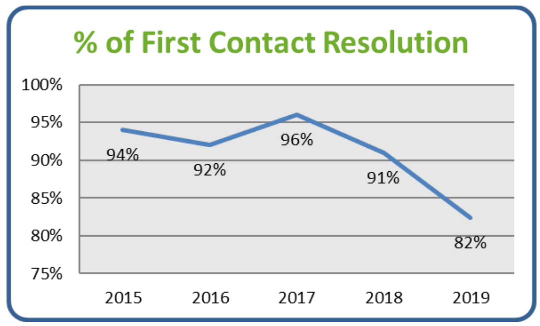
1.8.1.3 Telephone Calls Answered On Time

BHI answered telephone calls within 30 seconds over 74% of the time over the 2015-2019 period. BHI plans to continue to exceed the OEB target of 65%.



1.8.1.4 First Contact Resolution

BHI resolved customer concerns on first contact more than 82% of the time over the 2015-2019 period. BHI aims to address its customers' needs as quickly as possible and resolve customer concerns the first time the customer contacts BHI. In addition to its call centre, BHI uses a number of online electronic request forms that customers are able to complete themselves; these forms contribute to the high rate of First Contact Resolution.



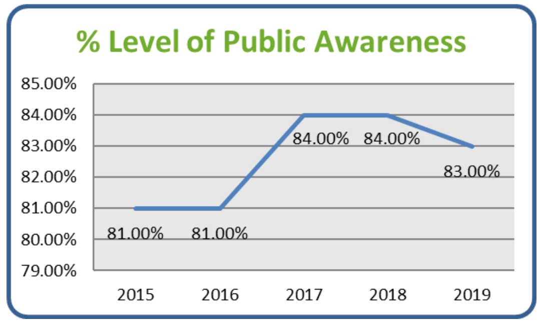
1.8.1.5 Billing Accuracy

BHI issued an accurate bill more than 99.7% of the time over the 2015-2019 period. BHI's continuous attention to detail and rigorous business processes have contributed to this performance. BHI plans to continue to exceed the OEB target of 98%.

1.8.1.6 Customer Satisfaction Survey Results

Engaging customers in a constantly changing energy environment is increasingly important. BHI commissions a customer satisfaction survey on an annual basis and these survey results provide valuable insights into customers' perceptions, needs and preferences both over time and relative to other LDCs. BHI tracks the percentage of customers that are satisfied with BHI overall and sets a target of 4% higher than the provincial average. BHI achieved this target every year with the exception of 2018, where BHI's overall customer satisfaction score was 3% above the provincial average.

1.8.1.7 Level of Public Awareness



BHI conducts a public awareness survey among a representative sample of its territory population. The survey measures awareness levels of key electrical safety concepts related to distribution assets and is based on a standard survey methodology developed by the Electrical Safety Authority ("ESA"). BHI's Level of Public Awareness has been above 81% over the 2015-2019 period. Initiatives that contribute to this level of awareness include:

- Responding, as requested, to public inquiries received through BHI's Health and Safety
- email box;
- Elementary school programs and children safety programs;
- Public safety video messaging; and
- City of Burlington Emergency Preparedness exercise.

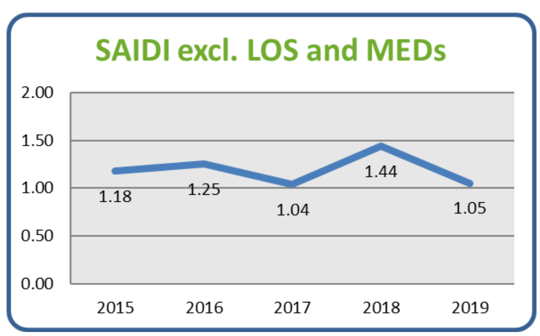
1.8.1.8 Level of Compliance with O.Reg. 22/04

Ontario Regulation 22/04 - Electrical Distribution Safety establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. BHI was compliant with Ontario Regulation 22/04 over the 2015-2019 period and plans to remain compliant in the future

1.8.1.9 Serious Electrical Incident Index: Number of General Public Incidents

BHI has had zero Serious Electrical Incidents and plans to maintain this safety performance.

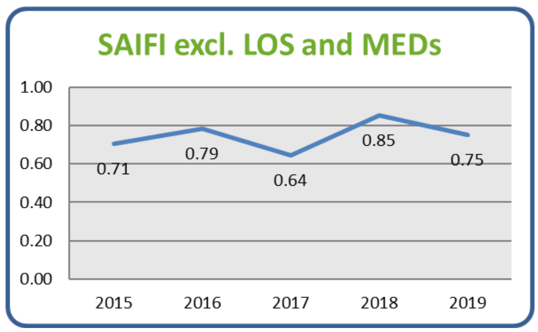
1.8.1.10 SAIDI



BHI's average System Average Interruption Duration Index ("SAIDI") performance, excluding Loss of Supply ("LOS") and Major Event Days ("MEDs"), was 1.19 over the 2015-2019 period, i.e., on average, customers experienced just over one hour in sustained interruptions annually, after adjusting for events beyond BHI's control (LOS and MEDs). SAIDI performance was higher than the target (1.09) in

2015, 2016 and 2018 due to a significant number of outages caused by defective equipment, adverse weather, and tree contacts. BHI's average SAIDI performance increased from 1.09 over the 2010-2014 period, to 1.20 over the 2015-2019 period, indicating customers are experiencing a longer duration of outages. BHI intends to maintain its five year historical SAIDI performance levels over the 2021-2025 period, through the system renewal investments proposed in this Application. This is consistent with feedback from customers who are supportive of BHI making investments in aging infrastructure in order to maintain reliability.

1.8.1.11 SAIFI



BHI's average System Average Interruption Frequency Index ("SAIFI") performance, excluding LOS and MEDs, was 0.75 over the 2015-2019 period, i.e., on average, customers experienced less than one sustained interruption annually, after adjusting for events beyond BHI's control (LOS and MEDs). BHI's SAIFI performance was better than the target (1.07) every year from 2015-2019. BHI's target is to maintain its average SAIFI performance from 2015-2019 which is consistent with feedback from customers.

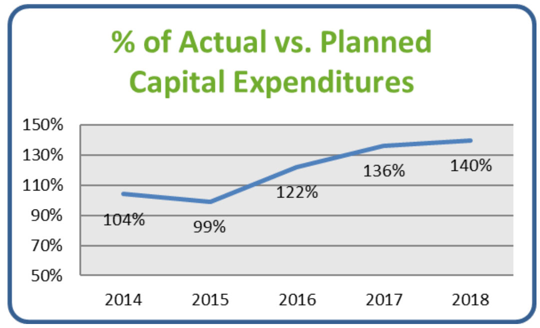
1.8.1.12 Distribution System Plan Implementation Progress

Historically, BHI used a binary qualitative metric to measure its DSP implementation progress: On-Track vs. Off-Track. BHI found that this metric did not provide enough information to take course corrective action or continuously improve its asset management and capital expenditure planning processes in a timely manner. BHI proposes to establish a new metric to measure the progress of its DSP implementation calculated as follows:

$$\textit{DSP Implementation Progress (\%)} = \frac{\textit{Annual Actual Capital Expenditures}}{\textit{Annual Planned Capital Expenditures}}$$

Planned expenditures for the historical period are based on BHI's previous plan for capital expenditures filed in its last rebasing application in 2014. BHI has not provided results for 2019 since its last DSP covered the period from 2014 to 2018.

In 2014 and 2015, actual capital expenditures were within 4% and 1% of planned capital expenditures, respectively. From 2016 to 2018, BHI's actual capital expenditures exceeded planned capital expenditures, driven by higher than planned replacement of assets at the end of their service life, an increase in mandatory system access projects to connect new customers to its distribution system, and investment in feeder egress cables from Tremaine TS to accommodate growth in NE Burlington.



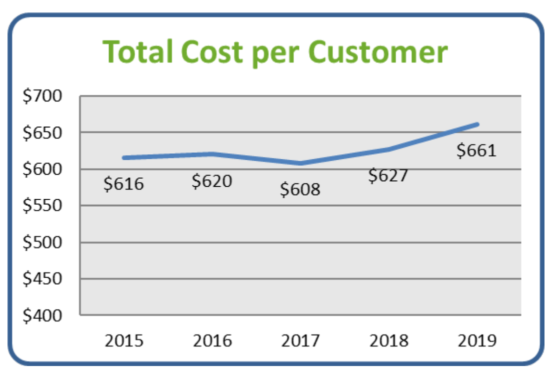
Since 2014, BHI has experienced the need to renew a growing number of assets at the end of their service lives, an increase in mandatory system access projects, and a limited capital budget, which has highlighted the need for BHI to:

- Enhance its methodology to allocate available capital funds; and
- Develop a consistent process to implement the methodology to ensure that:
  - All projects are evaluated against a standard set of criteria;
  - Project prioritization is objective and unbiased; and
  - Key outcomes are delivered as determined by BHI's asset management objectives.

These changes will facilitate the achievement of BHI's DSP implementation progress target of 100% for 2021-2025.

1.8.1.13 Total Cost per Customer

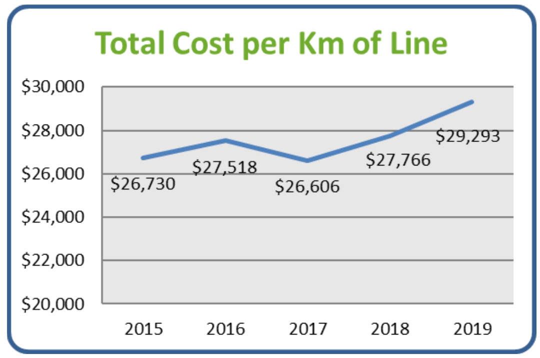
Total cost per customer is calculated as the sum of BHI's capital and operating costs divided by the total number of customers that BHI serves. BHI's total cost per customer has increased by an average of 1.8% per year over the 2015-2019 period, below the rate of inflation. BHI has experienced increases in its total costs required to deliver quality and reliable services to customers. Growth in wage and benefits costs for our employees, as well as investments in new information systems technology and the



renewal and growth of the distribution system, have all contributed to increased operating and capital costs. 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 condition, which require replacement over the next five years. In light of the condition and age of its assets, BHI plans to monitor this metric over the 2021 to 2025 period, relative to the 2021 Test Year amounts approved as part of this Application.

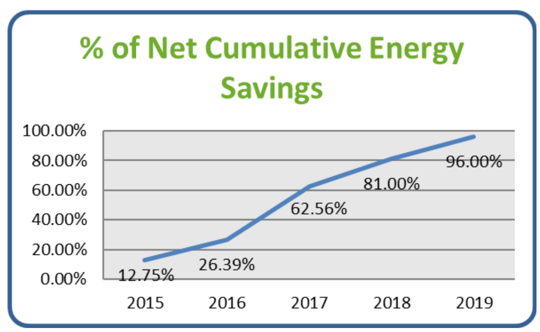
1.8.1.14 Total Cost per Km of Line

Total cost per km of line is calculated as the sum of BHI's capital and operating costs divided by the kilometers of line that BHI operates to serve its customers. BHI's total cost per km of line has increased by an average of 2.3% per year over the 2015-2019 period, which is a higher rate of increase compared to the total cost per customer due to the slower growth rate of km of line. As stated above, investment needs over the next five years will put upward pressure on this metric, which BHI plans to monitor.



1.8.1.15 Net Cumulative Energy Savings

On March 21, 2019, Ministerial Directives to the OEB and the Independent Electricity System Operator ("IESO") discontinued the 2015 to 2020 Conservation First Framework ("CFF") and established a scaled down Interim Framework for the balance of 2019 and 2020, to be delivered centrally by the IESO.



As part of the CFF, which was to run from 2015 to 2020, BHI was assigned a target of 99.04 GWh. To the end of 2019, BHI had achieved 95.08 GWh of savings, which equates to 96.0% of the original six-year target. BHI's success reflects strong residential participation in coupon and heating/cooling programs; and uptake of and participation in the Retrofit program by commercial and industrial customers.

1.8.1.16 Renewable Generation Connection Impact Assessments Completed On Time

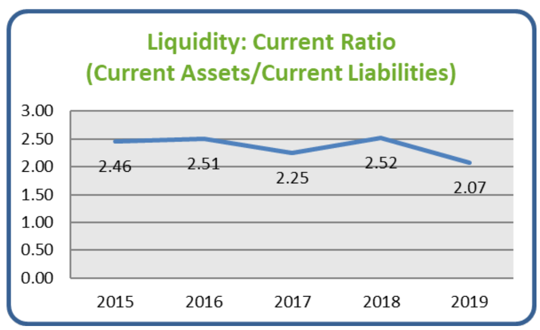
Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within 60 days of receiving a customer's application. BHI engages a consulting firm to assume overall responsibility for processing its connections. BHI has conducted CIAs within 60 days 100% of the time over the 2015-2019 period and plans to continue this performance.

1.8.1.17 New Micro-embedded Generation Facilities Connected On Time

The OEB requires electricity distributors to connect new micro-embedded generation facilities (Net Metering projects of less or equal than 10 kW) 90% of the time within the prescribed time frame of five business days. BHI engages a consulting firm to assume overall responsibility for processing its connections. BHI connected new micro-embedded generation facilities within five business days more than 97% of the time over the 2015-2019 period and plans to continue this performance.

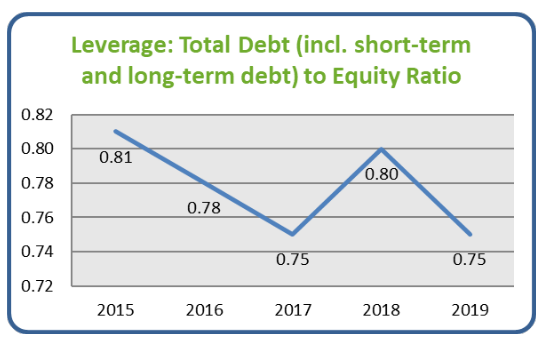
1.8.1.18 Liquidity: Current Ratio

The current ratio measures whether BHI has sufficient resources to meet its short-term debts/obligations (due within the next 12 months). BHI's current ratio has been above 2.00 over the 2015-2019 period, indicating it can settle its short-term debts with existing assets.

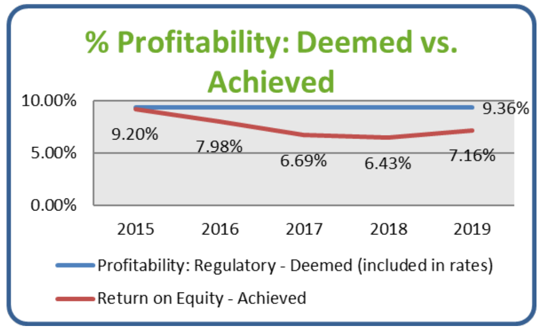


1.8.1.19 Leverage: Total Debt to Equity Ratio

The total debt-to-equity ratio measures the extent to which the assets of a company are financed by borrowing money. A debt-to-equity ratio of 1.00 means that half of the assets of a business are financed by debts and half by shareholders' equity. The OEB uses a deemed capital structure of 60% debt and 40% equity when establishing rates for electricity distributors, which is equal to a debt-to-equity ratio of 1.5 (60/40). BHI's total debt-to-equity ratio has been below the OEB's deemed debt-to-equity ratio of 1.5 over the 2015-2019 period.



1.8.1.20 Profitability: Deemed vs. Achieved



BHI's current distribution rates were approved by the OEB in the Settlement Agreement of its 2014 Cost of Service Application (EB-2013-0015) and include an expected (deemed) regulatory return on equity of 9.36%. The OEB allows electricity distributors to earn within +/- 3% of the deemed return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB. BHI's regulatory return on equity achieved over the 2015-2019 period falls within the 6.36% - 12.36% range allowed by the OEB.

1.8.2 Efficiency Assessment

Electricity distributors must manage their costs successfully in order to ensure customers are receiving appropriate value for the cost of service. The total costs of Ontario electricity distributors are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The OEB publishes a report each year on the benchmarking of electricity distributor cost performance based on this evaluation. As described in the OEB's Report of the Board on *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*[43], an econometric model is used to generate these efficiency rankings. Electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. These rankings are based on a three-year average cost performance.

BHI provides its historical cost performance and efficiency assessment performance from 2014 to 2019 in Table 37 below. BHI was assigned to Group 3 for 2014 and 2015, where a Group 3 distributor is considered "average efficiency" and defined as having actual costs within +/- 10% of predicted costs. In 2016, BHI/s costs were (11.1%) lower than its predicted costs which consequently lowered its three-year average cost performance and pushed the utility into Group 2. BHI has maintained an efficiency ranking of 2 since 2016.

[43] EB-2010-0379, p23

Table 37 – Historical Cost Performance

Description	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals
Percentage Difference (Cost Performance)	(9.4%)	(10.3%)	(11.1%)	(11.9%)	(13.9%)	(11.7%)
Three-Year Average Performance	(8.6%)	(9.0%)	(10.3%)	(11.1%)	(12.3%)	(12.5%)
Stretch Factor Cohort - Annual (Three Year Average)	**3**	**3**	**2**	**2**	**2**	**2**
Rate Year	2016	2017	2018	2019	2020	2021

BHI provides a forecast of its efficiency assessment using the PEG forecasting model for the 2021 Test Year for the purposes of providing the OEB with a directional indication of efficiency in Table 38 below. This model is attached as:
Attachment7_Benchmarking_Spreadsheet_Forecast_Model_BHI_10302020

Table 38 – Forecast of Efficiency Assessment

Description	2018 Actuals	2019 Actuals	2020 Bridge Year	2021 Test Year
Actual Total Cost	$42,620,320	$45,081,890	$45,648,700	$49,712,800
Predicted Total Cost	$48,967,761	$50,678,434	$50,557,582	$52,610,872
Actual Cost Greater Than/(Less Than) Predicted Cost	($6,347,441)	($5,596,544)	($4,908,882)	($2,898,072)
Percentage Difference (Cost Performance)	**(13.9%)**	**(11.7%)**	**(10.2%)**	**(5.7%)**
Three-Year Average Performance	(12.3%)	(12.5%)	(11.9%)	(9.2%)
Stretch Factor Cohort - Annual	2	2	2	3
Stretch Factor Cohort - Annual (Three Year Average)	2	2	2	3

BHI is experiencing a sustained need for capital investments in its distribution system primarily driven by mandatory System Access projects and System Renewal projects to replace assets at the end of their useful life. It has experienced operational, technological and regulatory changes which are putting upward pressure on operating expenses. Furthermore, the 2021 Test Year incorporates several cost increases due to policy changes which up until the 2021 Test Year had been recorded in deferral accounts and excluded from operating expenses in the PEG model e.g. the transition to monthly billing and regulatory costs.

BHI has made efforts to keep operating costs under control and find productivity improvements where possible; however the increase in capital and operating expenditure in the 2020 Bridge and 2021 Test Years results in a decrease in BHI's cost performance. Costs in the 2021 Test Year are expected to be (5.7%) lower than predicted costs, as identified in Table 38, which places the BHI in Group 3 in 2021. BHI expects to remain in Group 3 for the 2021-2025 Price Cap IR term.

1.9 FINANCIAL INFORMATION

1.9.1 Financial Statements

BHI has included its non-consolidated Audited Financial Statements ("AFS") for the years 2018 and 2019 as Appendix E and Appendix F respectively.

1.9.2 Reconciliation of Financial Statements

A detailed reconciliation between the AFS and the regulatory financial results filed in the application are included as Appendix G.

1.9.3 Annual Report and Management's Discussion and Analysis

BHI, nor its parent company BEC, produce publicly available annual reports or MD&As. BHI has included is 2019 Community Report as Appendix H.

1.9.4 Rating Agency Reports

BHI does not have any rating agency reports and there are no plans for public issuances.

1.9.5 Prospectuses and Information Circulars

BHI does not have any publicly traded debt or equity and there are no plans to issue public debt or equity.

1.9.6 Change in Tax Status

BHI is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service Application in 2014. BHI has not, nor is planning any future change in tax status.

1.9.7 Existing Accounting Orders

BHI has the following existing accounting orders, specific to BHI which are discussed in further detail in Section 1.4.13:

- Accounting Order – Costs - Implementation of Monthly Billing
- Accounting Order – Lost Revenue - Collection of Account Charges

1.9.8 Departures from the Uniform System of Accounts ("USoA")

BHI confirms it has not departed from the Uniform System of Accounts.

1.9.9 Accounting Standards

BHI adopted Revised CGAAP effective January 1, 2013 and IFRS effective January 1, 2015. These changes are discussed in further detail in Section 1.4.12.

1.9.10 Non-Distribution Business

BHI is not conducting non-distribution businesses, such as generation.

1.10 DISTRIBUTOR CONSOLIDATION

BHI has not acquired or amalgamated with any other distributor.

APPENDICES

Appendix A – Cost of Service Checklist

2021 Cost of Service Checklist
Burlington Hydro Inc.
EB-2020-0007

Date: October 30, 2020

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch 1, Pg. 2	Certification by a senior officer that the evidence filed is accurate, consistent and complete	Exhibit 1, Section 1.4.1 and Appendix C - Certification of Evidence
Ch 1, Pg. 3-4	Confidential Information - Practice Direction has been followed	Confirmed see Cover Letter Redacted
Ch 2, Pg. 1	Statement identifying all deviations from Filing Requirements	Exhibit1, Section 1.0
2	Chapter 2 appendices in PDF and live Microsoft Excel format; PDF and Excel copy of current tariff sheet	Exhibit 1, Section 1.4.11 (Chapter 2 Appendices); Exhibit 8 Appendix C and Attachment24_Excel_CurrentTariffSheet_BHI_10302020 (Current Tariff Sheet)
3	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year.	N/A - filing October 30,2020 for May 1, 2021 rates
3	Aligning rate year with fiscal year - request for proposed alignment	N/A - remaining on May 1 rates
4	Text searchable and bookmarked PDF documents	Confirmed
5	Links within Excel models not broken and models names so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed
5	Materiality threshold; additional details beyond the threshold if necessary (for rate base, capital expenditures and OM&A)	Exhibit 1, Section 1.4.6
RESS Guideline	Two hardcopies of application sent to OEB the same day as electronic filing (p10 of RESS Guideline)	N/A - June 23, 2020 OEB Digitization Program Announcement Letter
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
Table of Contents		
6	Table of Contents listing major sections and subsections of the application. Electronic version of application appropriately bookmarked to provide direct access to each section	Exhibit 1, Section 1.1
Executive Summary		
6	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by the Rate Handbook including plain language information about its goals	Exhibit 1, Section 1.2
Customer Summary		
7	Brief but complete summary of the application that will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to customers of the applicant. Must include: main requests (with section references), description of impacts of requests, bill impact for customer at 750kWh as well as a typical consumer for a distributor's service area for each of the residential and small business customer classes	Exhibit 1, Section 1.3 and Attachment1_Customer_Summary_BHI_10302020
Administration		
7	Primary contact information (name, address, phone, fax, email)	Exhibit 1, Section 1.4.2
7	Identification of legal (or other) representation	Exhibit 1, Section 1.4.3
7	Applicant's internet address for viewing of application and any social media accounts used by the applicant to communicate with customers	Exhibit 1, Section 1.4.4
7	Statement identifying customers materially affected by the application including any change to any rate or charge and specific statement of what individual customer or customer groups would be affected by the proposed change	Exhibit 1, Section 1.4.5
7	Statement identifying where notice should be published and why	Exhibit 1, Section 1.4.7
7	Bill impacts - distribution only impacts for 750 kWh residential and 2000 kWh GS<50 (sub-total A of Tariff Schedule and Bill Impact Spreadsheet Model) to be used for notice; proposed bill impacts based on alternative consumption profiles and customer groups as appropriate given consumption patterns of a distributors customers	Exhibit 1, Section 1.4.8
7	Form of hearing requested and why	Exhibit 1, Section 1.49
7	Requested effective date	Exhibit 1, Section 1.4.10
7	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1, Section 1.4.12
7	Identification of OEB directions from any previous OEB Decisions and/or Orders. The applicant must clearly indicate how these are being addressed in the current application (e.g., filing of a study as directed in a previous decision)	Exhibit 1, Section 1.4.13
7 & 8	Reference to Conditions of Service - LDC does not need to file Conditions of Service, but must provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit 1, Section 1.4.14
8	Description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit 1, Section 1.4.15
8	List of approvals requested (and relevant section of legislation), including accounting orders - a PDF copy of Appendix 2-A should be provided in this section	Exhibit 1, Section 1.4.16
Distribution System Overview		
8	Description of Service Area (including map, communities served)	Exhibit 1, Section 1.5
8	Description of whether the distributor is a host distributor and/or embedded distributor. Identification of embedded and/or host distributors; if partially embedded provide %load from host distributor. If the distributor is a host, the applicant should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes such as GS > 50 kW	Exhibit 1, Section 1.5
8	Statement as to whether or not the distributor has had any transmission or high voltage assets deemed by the OEB as distribution assets and whether or not there are any such assets the distributor is seeking approval for in this application	Exhibit 1, Section 1.5
Application Summary		
At a minimum, the items below must be provided. Applicants must also identify all proposed changes that will have a material impact on customers.		
9	Revenue Requirement - service RR, increase/decrease ($ and %) from change from previously approved and main drivers	Exhibit 1, Section 1.6 A
9	Budgeting and Accounting Assumptions - economic overview and identification of accounting standard used for test year and brief explanation of impacts arising from any change in standards	Exhibit 1, Section 1.6 B
9	Load Forecast Summary - load and customer growth, % change in kWh/kW and customer numbers, description of forecasting method(s) used for customer/connection and consumption/demand	Exhibit 1, Section 1.6 C
9	Rate Base and DSP - major drivers of DSP, rate base for test year, change in rate base from last approved ($ and %), capital expenditures requested for the test year, change in capital expenditures from last approved ($ and %), summary of costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives, any O.Reg 339/09 planned recovery	Exhibit 1, Section 1.6 D
9 & 10	OM&A Expense - OM&A for test year and change from last approved ($ and %), summary of drivers and cost trends, inflation assumed, total compensation for test year and change from last approved ($ and %).	Exhibit 1, Section 1.6 E

2021 Cost of Service Checklist

Burlington Hydro Inc.

EB-2020-0007

Date: October 30, 2020

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
10	Cost of Capital - summary table showing proposed capital structure and cost of capital parameters used in WACC. Statement regarding use of OEB's cost of capital parameters; summary of any deviations	Exhibit 1, Section 1.6 F
10	Cost Allocation & Rate Design - summary of any deviations from OEB methodologies, significant changes proposed to revenue-to-cost ratios and fixed/variable splits and summary of proposed mitigation plans	Exhibit 1, Section 1.6 G
10	Deferral and Variance Accounts - total disposition (RPP and non-RPP), disposition period, new accounts requested and any requested discontinuation of existing DVAs	Exhibit 1, Section 1.6 H
10	Bill Impacts - total impacts ($ and %) for all classes for typical customers	Exhibit 1, Section 1.6 I
Customer Engagement		
10	Discussion on how customers were informed of the proposals being considered for inclusion in the application and the value of those proposals to customers i.e. costs, benefits, and the impact on rates	Exhibit 1, Section 1.7
10	Discussion of any feedback provided by customers and how the feedback shaped the final application	Exhibit 1, Section 1.7
10	Impact of customer engagement activities on the development of the capital plan are to be filed as part of the capital plan requirements in Chapter 5	Exhibit 1, Section 1.7
11	Reference to any other communication sent to customers about the application i.e. bill inserts, town hall meetings or other forms of out reach and the feedback received from customers through these engagement activities. Provide summary of feedback received through engagement activities.	Exhibit 1, Section 1.7
11	Complete Appendix 2-AC Customer Engagement Activities Summary - explicit identification of the outcomes of customer engagement in terms of the impacts on the distributor's plans, and how that information has shaped the application	Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
11	All responses to matters raised in letters of comment filed with the OEB	N/A - no letters of comment to date
Performance Measurement		
11	Discussion of performance for each of the distributor's scorecard measures over the last five years; drivers for its performance, plans for continuous improvement currently and going forward	Exhibit 1, Section 1.8.1
11 & 12	Identify performance improvement targets, forecast of efficiency assessment using the PEG forecasting model for the test year, discussion on how the results obtained from the PEG model has informed the business plan and application	Exhibit 1, Section 1.8.2
Financial Information		
12	Non-consolidated Audited Financial Statements for 3 most recent historical years (i.e. 2 years statements must be filed, covering 3 years of historical actuals)	Exhibit 1, Section 1.9.1 and Appendices E and F in Exhibit 1
12	Detailed reconciliation of AFS with regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non-distribution business. This must include identification of any deviations that are being proposed between AFS and regulatory financial results, including the identification of any prior OEB approvals for such deviations	Exhibit 1, Section 1.9.2 and Appendix G in Exhibit 1
12	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	N/A - Exhibit 1, Section 1.9.3 - BHI or parent does not issue Annual report
12	Rating Agency Reports, if available; Prospectuses, etc. for recent and planned public issuances	N/A - Exhibit 1, Section 1.9.4; Exhibit 1, Section 1.9.5
12	Any change in tax status	N/A - Exhibit 1, Section 1.9.6
12	Existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1, Section 1.9.7; N/A - Exhibit 1, Section 1.8
12	Accounting Standards used for financial statements and when adopted	Exhibit 1, Section 1.9.9 and Section 1.4.12
12	Confirmation that accounting treatment of any non-utility business has segregated activities from rate regulated activities	N/A - Exhibit 1, Section 1.9.10
Distributor Consolidation		
13	If a distributor has acquired or amalgamated with another distributor, identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement. A distributor must specify whether any commitments made to shareholders are to be funded through rates	N/A - Exhibit 1, Section 1.10
13	List of exhibits in application in which incentives are discussed	N/A - Exhibit 1, Section 1.10
13	Description of actual savings as a result of consolidation compared to what was in the approved consolidation application and explanation of how savings are sustainable and the efficacy of any rate plan approved as part of the MAADs application	N/A - Exhibit 1, Section 1.10
13	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	N/A - Exhibit 1, Section 1.10
EXHIBIT 2 - RATE BASE		
Overview		
14	Completed Fixed Asset Continuity Schedule (Appendix 2-BA) - in Application and Excel format	Exhibit 2, Section 2.1.1.3 and Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
14	For rate base, must include opening and closing balances, average of opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance (historical actuals, bridge and test year forecast)	Exhibit 2, Section 2.1.1
14	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	Exhibit 2, Section 2.1.1.2
14 & 15	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. If not, an explanation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit 2, Sections 2.1.1 and 2.1.1.3
15	Distributor may include in-service balances previously recorded in DVAs, such as MIST meters or renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, but disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	N/A - Exhibit 2, Section 2.1.1.3
Gross Assets - PP&E and Accumulated Depreciation		
15	Breakdown by function and by major plant account; description of major plant items for test year	Exhibit 2, Section 2.1.2.1 and 2.1.2.2
15	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Exhibit 2, Section 2.1.2.1
15	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit 2, Section 2.1.1.3 and Exhibit 4, Section 4.4.1
15	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years and if any amounts related to gains or losses on disposals have been included in Account 1575 IFRS - CGAAP Transitional PP&E Amount	Exhibit 2, Section 2.1.2.4 and Exhibit 9, Section 9.1
Allowance for Working Capital		
16	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	Exhibit 2, Section 2.1.3
16	Lead/Lag Study - leads and lags measured in days, dollar-weighted	N/A - Exhibit 2, Section 2.1.3
16	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price, use current UTR. Calculation must fully consider all other impacts resulting from the Ontario Electricity Rebate of 31.8% on the total bill. Distributors must complete Appendix 2-Z - Commodity Expense.	Exhibit 2, Section 2.1.3.1 and Attachment6_2Z_OEB_Chapter2Appendices_BHI_10302020

2021 Cost of Service Checklist
Burlington Hydro Inc.
EB-2020-0007

Date: October 30, 2020

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Capital Expenditures		
17	DSP filed as a stand-alone document; a discrete element within Exhibit 2	Exhibit 2 - Appendix A
17	Overall summary of capital expenditures over the past five historical years, including the last OEB-approved amounts, as well as the bridge year and the test year. The summary must show capital expenditures, treatment of contributed capital, and additions and deductions from CWIP. As part of Exhibit 2, a distributor must also provide explanations of year-over-year variances and an explanation of the variance, if any, between the OEB-approved capital expenditure amount in the last rebasing year as compared to the actual expenditures for that year.	Exhibit 2, Section 2.2.2
17	Complete Appendix 2-AB - four historical years must be actuals, forecasts for the bridge and test years; at a minimum, for historical years, applicants must provide actual totals for each DSP category. If no previous plan has been filed, applicants are only required to enter their planned total capital budget in the "plan" column for each historical year and for the bridge year including the OEB-approved amount for the last rebasing year	Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Policy Options for the Funding of Capital		
18	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP). Provide cost and materiality calculations to demonstrate ACM qualification	Exhibit 2, Section 2.2.3
18	Distributor must establish need for and prudence of these projects based on DSP information; identification that distributor is proposing ACM treatment for these future projects, preliminary cost information	Exhibit 2, Section 2.2.3
18	Complete Capital Module Applicable to ACM and ICM	Attachment8_2021_ACM_ICM_Model_BHI_10302020
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
19	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base. The distributors must compare actual capital spending with OEB-approved amount and provide an explanation for variances	Exhibit 2, Section 2.2.4
20	Balances in Account 1508 sub-accounts, reconciliation with proposed rate base amounts; recalculated revenue requirement should be compared with rate rider revenue	Exhibit 2, Section 2.2.4
20	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Exhibit 2, Section 2.2.4 and Exhibit 9, Section 9.3.0.1.11
Capitalization Policy and Capitalization		
20	Changes to capitalization policy since its last rebasing application as a result of the OEB's letter dated July 17, 2012 or for any other reasons, the applicant must identify the changes and the causes of the changes.	Exhibit 2, Section 2.2.5
21	Appendix 2-D complete; identification of burden rates and burden rates prior to changes, if any	Exhibit 2, Section 2.2.6 and Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
21 & 22	Generation Facilities - If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09. Request for rate protection exceeds the materiality threshold in section 2.0.8 of the Filing Requirements - Appendices 2-FA through 2-FC identifying all eligible investments for recovery	N/A - Exhibit 2, Section 2.2.7
Service Quality		
22	5 historical years of SQRs, explanation for any under-performance vs standard and actions taken	Exhibit 2, Section 2.2.8
22	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Exhibit 2, Section 2.2.8 and Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Ch5 p7-8	Where applicable, explanation for section headings other than Chapter 5 headings; cross reference table	N/A - DSP, Section 5.1
Ch5 p8-9	Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies	DSP, Section 5.2.1
Ch5 p9-10	Coordinated Planning with 3rd parties - description of consultations - deliverables of the Regional Planning Process, or status of deliverables - IESO letter in relation to REG investments (Ch 5 p9) and Dx response letter	DSP, Section 5.2.2
Ch5 p10-12	Performance Measurement - identify and define methods and measures used to monitor DSP performance - summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply - explain how information has affected DSP	DSP, Section 5.2.3
Ch5 p12	Realized efficiencies due to smart meters -documented capital and operating efficiencies realized as a result of the deployment and operationalization of smart meters and related technologies. Both qualitative and quantitative descriptions should be provided	DSP, Section 5.2.4
Ch5 p12-13	Asset Management Process Overview - description of AM objectives/corporate goals and how Dx ranks objectives for prioritizing investments	DSP, Section 5.3.1
Ch5 p13	Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	DSP, Section 5.3.1
Ch5 p14	Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP), - description of system configuration - service profile and condition by asset type (tables and/or figures) - date data compiled - assessment of degree the capacity of system assets is utilized	DSP, Section 5.3.2
Ch5 p14-15	Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions - description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation	DSP, Section 5.3.3
Ch5 p15-16	System Capability Assessment for REG - REG applications > 10 kW, number and MW of REG connections for forecast period, capacity of Dx to connect REG, connection constraints	DSP, Section 5.3.4
Ch5 p16	Capital Expenditure Plan Summary for significant projects and activities to be undertaken - capability to connect new load or Gx customers, total annual capex over forecast period by investment category, description of how AMP and Capex planning have affected capital expenditures for each category - list, description and total capital cost of material capital expenditures sorted by category (table recommended) - information related to Regional Planning Process (Needs Assessment Report, Regional Planning Status Letter, Regional Infrastructure Plan - as appropriate) - description of customer engagement - Dx expectations of system development over next 5 years - list, description and total capital cost of projects planned in response to customer preferences, to take advantage of technology based opportunities, to study innovative processes (table recommended)	DSP, Section 5.4(a), 5.4(b), and 5.4.2.2
Ch5 p17-18	Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/ assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to priorities REG investments	DSP, Section 5.4.1

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Ch5 p18	Rate-Funded Activities to Defer Distribution Infrastructure -CDM programs that target distributor-specific peak demand reductions to address a local constraint of the distribution system -demand response programs to reduce peak demand in order to defer capital investment -programs to improve the efficiency of the distribution system and reduce distribution losses -energy storage programs whose primary purpose is to defer specific capital spending for the distribution system	N/A - DSP, Section 5.4.1.1
Ch5 p19-20	Capital Expenditure Summary by Investment Category - completed Table 2 of Ch 5 for historical and forecast period, explanation of markedly different variances plan vs actual, explanation of markedly different variances year over year Table 2 of Ch 5 is provided in Excel format in Appendix 2-AB (must provide actual totals for historical years, as a minimum) - Must also complete Chapter 2 Appendix 2-AA, along with explanations of variances by project or category, the proposed accounting treatments, a statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget	DSP, Section 5.4.2 and Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Ch5 p20	Justifying Capital Expenditures -filings must enable OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization, and pacing of capital-related expenditures -distributors should also keep pace with technological changes and integrate cost-effective innovative projects and traditional planning needs such as load growth, asset condition and reliability	DSP, Section 5.4.3
Ch5 p20-21	Overall Plan - comparative expenditures by category over historical period, forecast impact of system investment on O&M, drivers of investments by category, information related to Dx system capability assessment	DSP, Section 5.4.3
Ch5 p21-28	Material Investments - For each project that meets materiality threshold set in Ch 2 p5 - general information - total capital, customer attachments, dates, risks, variances, REG investments - evaluation criteria - may include: efficiency, customer value, reliability, etc. - category specific requirements for each project - system access, system renewal, system service, general plant (as applicable)	DSP, Section 5.4.3.2 and Appendix 1
EXHIBIT 3 - OPERATING REVENUE		
Load and Revenue Forecasts		
23	Explanation of causes, assumptions and adjustments for volume forecast, including economic assumptions and data sources for customer and load forecasts	Exhibit 3, Section 3.1
23	Explanation of weather normalization methodology	Exhibit 3, Section 3.1.1.1
23	Completed Appendix 2-IB; the customer and load forecast for the test year must be entered on RRWF, Tab 10	Attachment4_2I_OEB_Chapter2Appendices_BHI_10302020 and Attachment16_2020RRWF_BHI_10302020
23 & 24	Multivariate Regression Model - rationale for choice, regression statistics, explanation of weather normalization methodology, sources of data for endogenous and exogenous variables, any binary variables used to either account for individual data points or to account for seasonal or cyclical trends or for discontinuities in the historical data, explanation of any specific adjustments made; data used in load forecast must be provided in Excel format, including derivation of constructed variables	Exhibit 3, Section 3.1.1
24 & 25	NAC Model - rationale for choice, data supporting NAC variables, description of accounting for CDM including license conditions, discussion of weather normalization considerations	N/A - Exhibit 3, Section 3.1.2
25	CDM Adjustment - If a distributor expects impacts from any CFF-related projects not deployed by April 2019 but for which a distributor is contractually obligated to complete, or for other programs delivered by the distributor after April 2019, a distributor may include these amounts as part of a CDM manual adjustment to the 2021 load forecast but must ensure that sufficient supporting evidence is provided for all estimated CDM savings	Exhibit 3, Section 3.1.3
25	If a distributor proposes a CDM adjustment to its 2021 load forecast, it should document the CDM savings to be used as the basis for the 2021 LRAMVA threshold. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable to a customer class, kW. The distributor should document its proposal adequately	Exhibit 3, Section 3.1.3
25	Appendix 2-I - is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.	Attachment4_2I_OEB_Chapter2Appendices_BHI_10302020
Accuracy of Load Forecast and Variance Analyses		
25	Completed Appendix 2-IB	Attachment4_2I_OEB_Chapter2Appendices_BHI_10302020
25 & 26	For customer/connection counts - identification as to whether customer/connection count is shown in year end or average format, year-over-year variances in changes of customer/connection counts with explanation of major changes, explanations of bridge and test year forecasts by rate class, for last rebasing variance analysis between last OEB-approved and actuals with explanations for material differences	Exhibit 3, Section 3.2.1
26	For consumption and demand - explanation to support how kWh are converted to kW for applicable demand-billed classes, year-over-year variances in kWh and kW by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (should be done for both historical actuals against each other and historical weather-normalized actuals over time), explanations of the bridge and test year forecasts by rate class, variance analysis between the last OEB-approved and the actual and weather-normalized actual results	Exhibit 3, Section 3.2.2
26	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Exhibit 3, Section 3.2.4
26 & 27	With respect to average consumption, for each rate class, distributors are to provide weather-actual and weather-normalized average annual consumption or demand per customer as applicable for the rate class for last OEB approved and historical, weather normalized average annual consumption or demand per customer for the bridge and test years, explanation of the net change in average consumption from last OEB-approved and actuals from historical, bridge and test years based on year-over-year variances and any apparent trends in data	Exhibit 3, Section 3.2.5
Other Revenue		
27	Completed Appendix 2-H	Exhibit 3, Section 3.3.1 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
27	Variance analysis - year over year, historical, bridge and test	Exhibit 3, Section 3.3.2
27	Any new proposed specific service charges, or proposed changes to rates or application of existing specific service charges	Exhibit 3, Section 3.3.3
27	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs (Appendix 2-N)	Exhibit 3, Section 3.3.4 Exhibit 4, Section 4.3.2 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
28	Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges	Exhibit 3, Section 3.3.4
EXHIBIT 4 - OPERATING COSTS		
Overview		
29	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes	Exhibit 4, Section 4.1.0, Section 4.1.1, Section 4.1.2, Section 4.1.3, Section 4.1.4
Summary and Cost Driver Tables		
29	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit 4, Section 4.2 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020

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29	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit 4, Section 4.2 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
29	OM&A programs table; Appendix 2_JC	Exhibit 4, Section 4.3 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
29	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Exhibit 4, Section 4.1.2.11 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
29	Identification of change in OM&A in test year in relation to change in capitalized overhead.	Exhibit 4, Section 4.2 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
30	OM&A variance analysis for test year with respect to bridge and historical years; Appendix 2-D	Exhibit 4, Section 4.3 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Program Delivery Costs with Variance Analysis		
30	Completed Appendix 2-JC OM&A Programs Table - completed by program; include variance analysis between test year costs against each of the last OEB approved costs and most recent actuals for variances that are outliers based on historical trend. The variance analysis should explain whether the change was within or outside the applicant's control	Exhibit 4, Section 4.3 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
30	For each significant change within the applicant's control describe business decision that was made to manage the cost increase/decrease and the alternatives	Exhibit 4, Section 4.3.0.1 to 4.3.0.16 in each program Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
Workforce Planning and Employee Compensation		
30	Employee Compensation - completed Appendix 2-K	Exhibit 4, Section 4.3.1.4 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
30	Description of previous and proposed workforce plans, including compensation strategy	Exhibit 4, Section 4.3.1, Section 4.3.1.1, Section 4.3.1.2
30 & 31	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes: - year over year variances, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans, - relevant studies (e.g. compensation benchmarking)	Exhibit 4, Section 4.3.1, Section 4.3.1.2, Section 4.3.1.4
31	For virtual utilities - Appendix K must also be completed in relation to the employees of the affiliates who are doing the work of the regulated utility. The status of pension funding and all assumptions used in the analysis must be provided. Three or fewer employees - the applicant must aggregate this category with the 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.	N/A
31	Details of employee benefit programs including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit 4, Section 4.3.1.3 and Section 4.3.1.5
31	Most recent actuarial report	Exhibit 4, Appendix B
31	Accounting method for pension and OPEBs; if cash method, sufficient supporting rationale. If proposing to change the basis in which pension and OPEB costs included in OM&A, quantification of impact of transition	Exhibit 4, Section 4.3.1.5
Shared Services and Corporate Cost Allocation		
32	Identification of all shared services among affiliates and parent company; identification of the extent to which the applicant is a "virtual utility"	Exhibit 4, Section 4.3.2.1 and Section 4.3.2.2
32	Allocation methodology for corporate and shared services, pricing methodology, list of costs and allocators, including any third party review	Exhibit 4, Section 4.3.2.2 and Section 4.3.2.3
32	Completed Appendix 2-N for service provided or received for historical, bridge and test; including reconciliation with revenue included in Other Revenue	Exhibit 4, Section 4.3.2.4 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
32	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit 4, Section 4.3.2.6
32	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit 4, Section 4.3.2.7
Non-Affiliate Services, One-Time Costs, Regulatory Costs		
33	Purchased Non-Affiliated Services - file a copy of procurement policy (signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit 4, Section 4.3.3 Exhibit 4, Appendix C
33	For material transactions that are not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	N/A - Exhibit 4, Section 4.3.3
33	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test (or future years). If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	Exhibit 4, Section 4.3.4
33	Regulatory costs - breakdown of actual and anticipated regulatory costs, including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), proposed recovery (i.e. amortized?) Completed Appendix 2-M	Exhibit 4, Section 4.3.5 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
33	Information supporting the incremental level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify over what period the costs are proposed to be recovered. For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the Price Cap IR option (i.e. five years). If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.	Exhibit 4, Section 4.3.5
LEAP, Charitable and Political Donations		
33 & 34	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes	Exhibit 4, Section 4.3.6
34	Detailed information for all contributions that are claimed for recovery	Exhibit 4, Section 4.3.6
34	Charitable Donations - the applicant must confirm that no political contributions have been included for recovery	Exhibit 4, Section 4.3.7
Depreciation, Amortization and Depletion		
34	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	N/A - Exhibit 4, Section 4.4
34 & 35	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Exhibit 4, Section 4.4.2 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
35	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	Exhibit 4, Section 4.4.1
35	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit 4, Section 4.4.1
35	Copy of depreciation/amortization policy, or equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit 4, Section 4.4.1
35	Explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	N/A - Exhibit 4, Section 4.4.1

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35 & 36	For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes, including any changes subsequent to those made by January 1, 2013 -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA, detail differences in TUL from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB	Exhibit 4, Section 4.4.3
PILs and Property Taxes		
36	Completed version of the PILs model (PDF and Excel); derivation of adjustments for historical, bridge, test years	Attachment17_2021_PILS_Workform_BHI_10302020 PDF and Excel
36	Supporting schedules and calculations identifying reconciling items	Exhibit 4, Section 4.5.1.4 Attachment17_2021_PILS_Workform_BHI_10302020 PDF and Excel
36	Most recent federal and provincial tax returns	Exhibit 4, Section 4.5.1.1 Exhibit 4, Appendix E
36	Financial Statements included with tax returns if different from those filed with application	N/A, Appendices E and F in Exhibit 1
36	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	Exhibit 4, Section 4.5.1.3
36	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit 4, Section 4.5.1.4 Attachment17_2021_PILS_Workform_BHI_10302020 PDF and Excel
37	Completion of the integrity checks in the PILs Model	Attachment17_2021_PILS_Workform_BHI_10302020 PDF and Excel
37	Accelerated CCA - distributors must bring forward the balance tracked in Account 1592 - PILs and Tax Variances – CCA Changes for review and disposition in its current cost-based rate application, as well as future cost-based rate applications.	Exhibit 4, Section 4.5.4 Exhibit 9, Section 9.3.0.1
38	Explanation of how taxes other than income taxes or PILS (e.g. property taxes) are derived	Exhibit 4, Section 4.5.2
Non-recoverable and Disallowed Expenses		
38	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit 4, Section 4.5.3
Conservation and Demand Management		
40 - 43	LRAMVA - disposition of balance. Distributors must provide version 5 of LRAMVA Work Form (Excel) when making LRAMVA requests for remaining amounts related to CFF activity. An application for lost revenues should include: Participation and Cost reports in Excel format, made available by the IESO An application for lost revenues should also provide: - statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition - statement confirming LRAMVA based on verified savings results supported by the distributors final CDM Report and Persistence Savings Report (both filed in Excel format). - LRAMVA claim may be based on the information in that report at the time of filing of the application, but it is expected that the claim will be updated when the Final CDM Results Report is issued, and that the approved disposition will reflect the Final Results Report - statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation - summary table with principal and carrying charges by rate class and resulting rate riders - statement providing the disposition period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders - details for the forecasted CDM savings included in the LRAMVA calculation including reference to the OEBs approval, or an explanation if there are no forecast CDM savings - rationale confirming how rate class allocations for actual CDM savings were determined by class and program (Tab 3-A of LRAMVA Work Form) - statement confirming whether additional documentation was provided in support of projects that were not included in distributors final CDM Annual Report (Tab 8 of LRAMVA Work Form as applicable) - for a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: Explanation of the methodology to calculate street lighting savings; Confirmation whether the street lighting savings were calculated in accordance with OEB-approved load profiles for street lighting projects; Confirmation whether the street lighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate street lighting savings For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information: o Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application o Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans) o Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total) o Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program o A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb). For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information: The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate, the rationale for net-to-gross assumptions used, a breakdown of billed demand and detailed level calculations in live excel format Participation and Cost Reports and detailed project level savings files made available by the IESO to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available. These reports should be filed in excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017. o If a distributor seeks to claim any additional program savings to December 31, 2019: - Related to CCF programs: an explanation must be provided as to how savings have been estimated based on the available data (i.e. IESO's Participation & Cost Reports) and/or rationale to justify the eligibility of the program savings	Exhibit 4, Section 4.6.1 and Section 4.6.2 Attachment15_2021_LRAMVA_Workform_BHI_10302020
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
Capital Structure		
43	Statement that LDC adopts OEB's guidelines for cost of capital and confirms that updates will be done. Alternatively - utility specific cost of capital with supporting evidence	Exhibit 5, Section 5.1, Section 5.2.2 and 5.2.3
43	Completed Appendix 2-OA for last OEB approved and test year	Exhibit 5, Section 5.1 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
43	Completed Appendix 2-OB for historical, bridge and test years	Exhibit 5, Section 5.1 Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
44	Explanation for any changes in capital structure	N/A Exhibit 5, Section 5.1
Cost of Capital (Return on Equity and Cost of Debt)		
44	Calculation of cost for each capital component	Exhibit 5, Section 5.2
44	Profit or loss on redemption of debt	N/A - Exhibit 5, Section 5.2
44	Copies of promissory notes or other debt arrangements with affiliates	Exhibit 5, Appendix B
44	Explanation of debt rate for each existing debt instrument	N/A - Exhibit 5, Section 5.2.3 and 5.2.4
44	Forecast of new debt in bridge and test year - details including estimate of rate	Exhibit 5, Section 5.2.4

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44	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	N/A - Exhibit 5, Section 5.2
44 & 45	Notional Debt - should attract the weighted average cost of actual long-term debt rather than the current deemed long-term debt rate issued by the OEB	Exhibit 5, Section 5.2.6
Not-for-Profit Corporations		
45	The requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	N/A - Exhibit 5, Section 5.3
45	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to build up operating and capital reserves or will be used for other purposes	N/A - Exhibit 5, Section 5.3
45	If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves, provide the specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	N/A - Exhibit 5, Section 5.3
45	If the revenues derived from the return on equity component of the cost of capital will be used for other purposes, provide a statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities). Provide rationale supporting the use of the revenues in this manner. Also provide the governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities	N/A - Exhibit 5, Section 5.3
46	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	N/A - Exhibit 5, Section 5.3
EXHIBIT 6 - REVENUE DEFICIENCY/SUFFICIENCY		
46	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) and for which disposition is not being sought in the application.	Exhibit 6, Section 6.2
46	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit 6, Section 6.3
46	Impacts of any changes in methodologies to deficiency/sufficiency	Exhibit 6, Section 6.3.1
Revenue Requirement Work Form		
47	RRWF - in PDF and Excel. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Exhibit 6, Appendix A and Attachment16_2020RRWF_BHI_10302020
47	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	N/A - Exhibit 6, Section 6.4
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
48	Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. Sheets 11 and 12 of the RRWF must also be completed. Updated load profiles or scaled version of HONI CAIF. Model must be consistent with test year load forecast, changes to customer classes and load profiles.	Exhibit 7, Section 7.1 and Attachment16_2020RRWF_BHI_10302020
48	Explanation provided if a distributor is unable to update its load profiles and confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed	N/A - Exhibit 7, Section 7.1
49	Provide spreadsheet and a description with example calculations to show how the demand data in the cost allocation model was derived from the load forecast and load profiles	Exhibit 7, Section 7.1
49	Description of weighting factors, and rationale for use of default values (if applicable)	Exhibit 7, Section 7.1
49	If using OEB-issued model, hard copy of sheets I-6, I-8, O-1 and O-2 (first page). If using another model, the distributor must file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live Microsoft Excel cost allocation model, whether using the OEB-issued one or a different model, with the application.	Exhibit 7, Appendix A and Attachment19_2021_Cost_Allocation_Model_v1.0_BHI_10302020
49 & 50	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF, Sheet 11 - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges); include in cost allocation study and RRWF, Sheet 11 - if embedded Dx billed as GS customer - , include with the GS class in cost allocation model and Appendix 2-P. Provide cost of serving, load served, asset ownership information, distribution charges, appropriateness of rate class. File Appendix 2-Q.	N/A - Exhibit 7, Section 7.1.1.2
50	Unmetered Loads (including Street Lighting) - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges	Exhibit 7, Section 7.1.1.3
50 & 51	microFIT - if the applicant believes that it has unique circumstances which would justify a certain rate, appropriate documentation must be provided	N/A - Exhibit 7, Section 7.1.1.4
51	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	N/A - Exhibit 7, Section 7.1.1.5
51	New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS	N/A - Exhibit 7, Section 7.1.2
Class Revenue Requirements		
52	To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.	Exhibit 7, Section 7.2
Revenue to Cost Ratios		
53	If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.	Exhibit 7, Section 7.3
53	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	Exhibit 7, Section 7.3
EXHIBIT 8 - RATE DESIGN		
54	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places	Exhibit 8, Section 8.1
Fixed Variable Proportion		
54	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V with supporting info -Proposed F/V proportion with explanation for any changes (billing determinants from proposed load forecast) -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Exhibit 8, Section 8.1
Rate Design Policy		

2021 Cost of Service Checklist

Burlington Hydro Inc.

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Date: October 30, 2020

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
55	Applicants that are still transitioning to fully fixed residential rates should refer to the approach to implementation of the policy, including mitigation expectations, was described in a letter from the OEB published on July 16, 2015	N/A - Exhibit 8, Section 8.2
RTSRs		
55	Retail Transmission Service Rate Work Form - PDF and Excel	Exhibit 8, Appendix A and Attachment21_2021_RTSR_Workform_BHI_10302020
55	RTSR information must be consistent with working capital allowance calculation	Exhibit 8, Section 8.3
Retail Service Charges		
55	If proposing changes to Retail Service Charges or introduction of new rates and charges - evidence of consultation and notice	N/A - Exhibit 8, Section 8.4
55	Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) will dispose of the balances and the RCVAs will be eliminated. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement	Exhibit 8, Section 8.4
Regulatory Charges		
56	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	N/A - Exhibit 8, Section 8.5
Specific Service Charges		
56	Specific Service Charge description/purpose/reason for new and revised SSC; calculations to support charges	Exhibit 8, Section 8.6
56	Identification in the Application Summary all proposed changes that will have a material impact on customers, including charges that may affect a discrete group	Exhibit 1, Section 1.4.5
57	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to 2019 and the revenue forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	N/A - Exhibit 8, Section 8.6
57	Ensure revenue from SSCs corresponds with Operating Revenue evidence	Exhibit 8, Section 8.6
Wireline Pole Attachment Charge		
56	Record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charge	Exhibit 8, Section 8.6.1
57 & 58	Distributors applying for an LDC-specific pole attachment charge must file: - statement confirming the proposed distributor-specific pole attachment charge, the year of data used, effective date - statement discussing main cost drivers for changes to charge including rationale - table summarizing key inputs in calculation, statement confirming that the RRR data (i.e. Account 1830, 5120) and pre-tax weighted cost of capital are consistent with the data filed in other cost of service models - confirmation of the total number of poles and joint use poles in the rate calculation, and a table outlining the rate of pole replacements and percentage of poles depreciated over the past five years - confirmation of the number of attachers that are specific to the distributor's service territory, if a different attacher number than the default number of 1.3 is proposed. A description of the types of attachments on poles, and a discussion of contractual arrangements with other entities that affect the number of attachments, including overlashing attachments, that are counted as part of the LDC's distribution poles - explanation of changes to the hybrid equal sharing allocation rate, if applicable, and the drivers of the proposed change - description of the activities performed by the distributor to directly accommodate third party attachers. Distributors should include a discussion of the methodology, costs and data sources to calculate each component of direct costs. Distributors should show the detailed calculations of total administration and LOP costs, including staff time and labour rates, as applicable - use of utility-specific costs to determine the LDC-specific Power Deduction Factor and LDC-specific Maintenance Allocation Factor applicable to third parties. If a distributor chooses to adopt the default factors in its application for a custom charge, a distributor is still required to complete Table 8 and Table 10-a of the Pole Attachment Workform to substantiate the applicability of the default factors that were used in calculating the provincially approved charge.	N/A - Exhibit 8, Section 8.6
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
58	Forecast of LV cost, sum of host distributors charges	N/A - Exhibit 8, Section 8.7
58	Low Voltage Cost (historical, bridge, test), variances and explanations for substantive changes	N/A - Exhibit 8, Section 8.7
59	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	N/A - Exhibit 8, Section 8.7
59	Allocation of LV cost to customer classes (typically proportional to Tx connection revenue)	N/A - Exhibit 8, Section 8.7
59	Proposed LV rates by customer class	N/A - Exhibit 8, Section 8.7
Smart Meter Entity Charge		
59	Distributor must follow accounting guidance provided on March 23, 2018	Exhibit 8, Section 8.8
Loss Factors		
59	Proposed SFLF and Total Loss Factor for test year	Exhibit 8, Section 8.9
59	Statement as to whether LDC is embedded including whether fully or partially	Exhibit 8, Section 8.9
59	Study of losses if required by previous decision	N/A - Exhibit 8, Section 8.9
59	3-5 years of historical loss factor data - Completed Appendix 2-R	Exhibit 8, Section 8.9 and Attachment2_Main_OEB_Chapter2Appendices_BHI_10302020
59	If proposed loss factor >5%, explanation and action plan to reduce losses going forward	N/A - Exhibit 8, Section 8.9
60	Explanation of SFLF if not standard	N/A - Exhibit 8, Section 8.9
Tariff of Rates and Charges		
60	Current and proposed Tariff of Rates and Charges filed in the Tariff Schedule/Bill Impacts Model - **must be filed in Excel format** Explanation and support of each change in the appropriate section of the application	Exhibit 8, Appendix B and C and Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020 and Attachment24_Excel_Current_Tariff_Sheet_BHI_10302020
60	Explanation of changes to terms and conditions of service if changes affect application of rates	N/A - Exhibit 8, Section 8.10
60	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Exhibit 8, Appendix C and Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020
Revenue Reconciliation		
60	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Exhibit 8, Section 8.11

2021 Cost of Service Checklist

Burlington Hydro Inc.

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
60	Completed RRWF - Sheet 13 - rates and charges entered on this sheet should be rounded to the same decimal places as tariff	Exhibit 8, Section 8.11 and Attachment16_2020RRWF_BHI_10302020
Bill Impact Information		
61	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020
61	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Exhibit 8, Section 8.12 and Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020
61	Rates and charges input in the tariff schedule and Bill Impacts Model rounded to the decimal places as shown on the existing tariff	Exhibit 8, Section 8.12 and Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020
61	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh, residential at the lowest 10th percentile and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory.	Exhibit 8, Section 8.12 and Attachment22_Tariff_Schedule_and_Bill_Impact_Model_BHI_10302020
61	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	N/A - Exhibit 8, Section 8.12
Rate Mitigation		
62	For distributors still in the process of moving to fully fixed residential rates - evaluation of bill impact for residential customer at 10th consumption percentile. Describe methodology for determination of 10th consumption percentile. File mitigation plan for whole residential class if impact >10% for these customers.	N/A - Exhibit 8, Section 8.13.1
62	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification, revised impact calculation. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	N/A - Exhibit 8, Section 8.13.2
62	Rate Harmonization Plans, if applicable - including impact analysis	N/A - Exhibit 8, Section 8.13.3
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
63	List of all outstanding DVA and sub-accounts; provide description of DVAs that were used differently than as described in the APH	Exhibit 9, Section 9.0.1
63	Completed DVA continuity schedule for period following last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding deferral and variance accounts. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the Electricity Reporting and Record-keeping Requirements	Exhibit 9, Section 9.0.2 and Attachment18_DVA_Continuity_Schedule_BHI_10302020
63	Confirm use of interest rates established by the OEB by month or by quarter for each year	Exhibit 9, Section 9.0.3
63	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	Exhibit 9, Section 9.0.4
63	Identification of Group 2 accounts that will continue/discontinue going forward, with explanation	Exhibit 9, Section 9.0.5
63	Statement as to any new accounts, and justification.	Exhibit 9, Section 9.0.6
63 & 64	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. Distributors to refer to OEB letter of October 2019 in addressing accounting or other errors in respect of Group 1 deferral and variance accounts that have previously been disposed of by the OEB on a final basis. Applicants must provide explanations for the nature and the amounts of adjustments, and include appropriate supporting documentation, under a section titled “Adjustments to Deferral and Variance Accounts”.	Exhibit 9, Section 9.0.7
64	Breakdown of energy sales and cost of power by USoA - as reported in AFS mapped and reconciled to USoA. Provide explanation if making a profit or loss on commodity.	Exhibit 9, Section 9.0.8
64	Completed GA Analysis Workform for each year since the OEB last approved disposition of Account 1589 - Global Adjustment irrespective of whether they are seeking disposition of the Account 1589 – RSVA GA balance as part of their current application. If the distributor is adjusting the Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589.	Exhibit 9, Section 9.0.9 and Attachment23_GA_Analysis_Workform_BHI_10302020
64	Statement confirming distributor has complied with OEB guidance of February 21, 2019 on the accounting for Accounts 1588 and 1589	Exhibit 9, Section 9.0.10 and 9.3.2
64	Completed 1589 Analysis Workform for residual balances that meet the eligibility requirements for dispositions of Account 1595 sub-accounts	Exhibit 9, Section 9.0.10 and 9.3.2
Account 1575, IFRS-CGAAP Transitional PP&E Amounts		
64	For applicants that have already rebased under revised CGAAP, but have made further material transitional changes, these impacts should be recorded in Account 1575, and an explanation provided	Exhibit 9, Section 9.1
Retail Service Charges		
65	Retail Service Charges - if material debit or credit balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances - state whether Article 490 of APH has been followed; explanation if not followed	Exhibit 9, Section 9.2
65	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account would be refunded to ratepayers in a future rate application, and the new account subsequently closed. Distributors can forecast a balance up to December 31, 2020 or April 30, 2021 and the OEB may consider disposing of the forecasted amount	Exhibit 9, Section 9.2
Disposition of Deferral and Variance Accounts		
65	Identify all accounts for which LDC is seeking disposition; identify DVA for which LDC is not proposing disposition and the reasons why	Exhibit 9, Section 9.3.0
65	Statement whether DVA balances before forecasted interest match the last AFS; explain any variances	Exhibit 9, Section 9.3.0 and 9.0.4
65	If the RRR balances do not agree to the year-end balances in the continuity schedule, a distributor must reconcile and explain the difference(s). For any utility specific accounts requested for disposition (e.g. Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived must be provided. The relevant accounting order must also be provided	Exhibit 9, Section 9.3.0 and 9.0.4 Exhibit 9, Section 9.3.0.1.3 Appendix C - Accounting Order Monthly Billing Transition Costs Exhibit 9, Section 9.3.0.1.5 Appendix D - Accounting Order Lost Revenue from Collection of Account Charge
66	Request final disposition of residual balances for vintage Account 1595 sub-accounts only once. Distributors are expected to seek disposition of the audited account balance in the fourth rate year after the expiry of the rate rider	N/A - Exhibit 9, Section 9.0.11
66	Proposed mechanisms for disposition with all relevant calculations: - allocation of each account (including rationale) - proposed billing determinants, including charge type, for recovery purposes in accordance with Rate Design Policy	Exhibit 9, Section 9.3.0.3
66	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	Exhibit 9, Section 9.3.0.3
66	Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period must provide explanation	Exhibit 9, Section 9.3.0.3

2021 Cost of Service Checklist

Burlington Hydro Inc.

EB-2020-0007

Date: October 30, 2020

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
66	Establish separate rate riders to recover balances in the RSVA's from Market Participants who must not be allocated the RSVA balances related to charges for which the MP's settle directly with the IESO	N/A - Exhibit 9, Section 9.3.0.4
66 & 67	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. - In the DVA continuity schedule, applicants must indicate whether they serve any Class A customers during the period where Account 1580 CBR Class B sub-account balance accumulated. In the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance - The DVA continuity schedule will allocate the portion of Account 1580 sub-account CBR Class B allocated to customers who transitioned between Class A and Class B based on consumption levels	Exhibit 9, Section 9.3.0.3, Section 9.3.0.5
Global Adjustment		
68	Establishment of a separate rate rider included in the delivery component of the bill that would apply prospectively to Non-RPP Class B customers when clearing balances from the GA Variance Account	Exhibit 9, Section 9.3.1.0
68	GA Analysis Workform in live Excel format for each year that has not previously been approved by the OEB for disposition (on an interim or final basis), irrespective of whether or not seeking disposition of Group 1 deferral and variance account balances. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589	Exhibit 9, Section 9.3.1.1 and Attachment23_GA_Analysis_Workform_BHI_20201030
68	As part of Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences pertaining to factors such as an outstanding IESO settlement true-up payment. The explanatory items should reduce the discrepancy and provide distributor-specific information to the OEB. Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition of the balance is approved. Any unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Exhibit 9, Section 9.3.1.1 and Attachment23_GA_Analysis_Workform_BHI_20201030
69	Commodity Accounts 1588 and 1589 - confirmation as part of the application that the distributor has fully implemented the OEB's February 21, 2019 guidance effective from January 1, 2019.	Exhibit 9, Section 9.3.2
69	In order to request for final disposition of historical balances as part of the current application, distributors must provide confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Distributors must also discuss the results of the review, whether any systemic issues were noted, and whether any material adjustments to those balances have been recorded. A summary and description of each adjustment made to the historical balances must also be provided in the application.	Exhibit 9, Section 9.3.2
69 & 70	Expectations of final disposition requests of commodity pass-through account balances are: - Some utilities may have received approval for interim disposition of historical account balances or did not request disposition of account balances in a prior rate application due to the threshold test. If these utilities have reviewed the balances in the context of the new accounting guidance and are confident that there are no systemic issues with their RPP settlement and related accounting processes, utilities may request final disposition of account balances. If these utilities identified errors or discrepancies that materially affect the ending account balances, utilities should adjust their account balances prior to requesting final disposition - Utilities that did not receive approval for disposition of historical account balances due to concerns noted should apply the accounting guidance to those balances and adjust the balances as necessary, prior to requesting final disposition. Adjustments to account balances will be considered on a case by case basis.	N/A - Exhibit 9, Section 9.3.2
70	If February 21, 2019 accounting guidance not fully implemented, a distributor must provide an explanation as to why this guidance has not been implemented, the status of the implementation process, and the expected implementation date. In addition, the distributor must complete and submit Appendix A – GA Methodology Description that can be found in the GA Analysis Workform Instructions	N/A - Exhibit 9, Section 9.3.2
70	Certification by the CEO, CFO or equivalent that distributor has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being proposed for disposition	Exhibit 9, Section 9.3.2.1 Exhinit 9, Appendix B
Establishment of New Deferral and Variance Accounts		
70 & 71	New DVA - information provided which addresses that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order.	N/A - Exhibit 9, Section 9.4

Appendix B – BHI 2021 Business Plan

Burlington hydro inc.

2021

BUSINESS PLAN

CONFIDENTIAL

GridSmartCity

BURLINGTON HYDRO INC.

Table of Contents

PART B:
BURLINGTON HYDRO INC. 2021 PRO FORMA & FINANCIAL STATEMENTS

Executive Summary

The Shareholder Direction provided by the City of Burlington requires that Burlington Enterprises Corporation (BEC), formally Burlington Hydro Electric Inc., and its subsidiaries, including Burlington Hydro Inc. (BHI or Burlington Hydro), conduct an annual strategic planning process and subsequently prepare and present to the City a Business Plan and 10 Year Forecast, 45 days prior to the calendar year end.

The goal of the strategic planning exercise is to clarify the 2021 role of Burlington Hydro and lay out a strategic roadmap for the company as the Plan is formulated and translated into specific action items/goals and objectives. The strategy session for the 2021 Business Plan, which included a 2020 update, was held with the Board of Directors on May 25, 2020 as a virtual Zoom meeting.

The 2021 Business Plan provides an overview of how the business landscape has changed due to the coronavirus pandemic and how Burlington Hydro will continue to manage its impact. This includes:

- Managing revenue losses as a result of lower customer demand and consumption, and bad debt associated with customer defaults; and,
- Managing expenditures to ensure business continuity and employee safety measures are in place (i.e. setting up a second control room, an additional off-site operations centre, protocols for working from home, office measures to ensure a safe work environment, etc.);

It also includes supporting customers with financial hardship to pay electricity bills by offering payment options/arrangements and promoting assistance programs that they may qualify for (e.g. COVID-19 Energy Assistance Plan [CEAP], LEAP, OESP).

Attention in 2021 will also focus on a number of primary projects/initiatives that provide positive movement forward for the company and its customers, and includes:

- the completion of a successful Cost of Service Rate Filing to the Ontario Energy Board (OEB) – see page 17 ;
- the roll out and implementation of a new Customer Information System – see page 21; and,
- deployment of the latest cyber security tools and ongoing improvement of BHI’s Information Security Management Program – see page 22.

Company History

Established in 1945, Burlington Hydro is a local distribution company (LDC) serving the City of Burlington, with a total licensed service area of 188 square kilometres and a customer base of approximately 68,000 customers (consisting of Residential, General Service, Street Light, and Unmetered Scattered Load customers/connections). The company celebrated its 75th Anniversary in 2020.

Following changes to the *Electricity Act* and the introduction of the *Energy Competition Act* in 1998, Burlington Hydro Electric Inc. was reinvented as a private corporation. Formally, Burlington Hydro had operated in a not-for-profit capacity as a hydro-electric commission (HEC) with powers laid out under the Public Utilities Act and the Power Corporation Act (very similar to the crown-owned Ontario Hydro).

Burlington Hydro was incorporated and wholly transferred into the ownership of the City of Burlington on January 1, 2000 as a for-profit company. At that time, the City created a holding company, Burlington Hydro Electric Inc., to oversee two subsidiary companies: a regulated "wires" company, Burlington Hydro Inc., and an unregulated company, Burlington Electricity Services Inc.

In 2019, the governance model for the holding company, Burlington Hydro Electric Inc. (BHEI), was re-structured and renamed Burlington Enterprises Corporation (BEC), to better align with the governance structure supported/preferred by the Ontario Energy Board (OEB).

Governance Structure

"The OEB's objectives in setting out best practices and introducing new reporting on governance are to build upon the OEB's focus on utility performance and to allow the OEB to obtain insight into the quality and robustness of decision-making of the utility business. The combination of identified best practices and mandatory reporting are expected to support the OEB's ability to rely upon utility governance as an indicator of utility performance." *(December 2018, "Best Practices regarding Governance of OEB Rate-Regulated Utilities")*

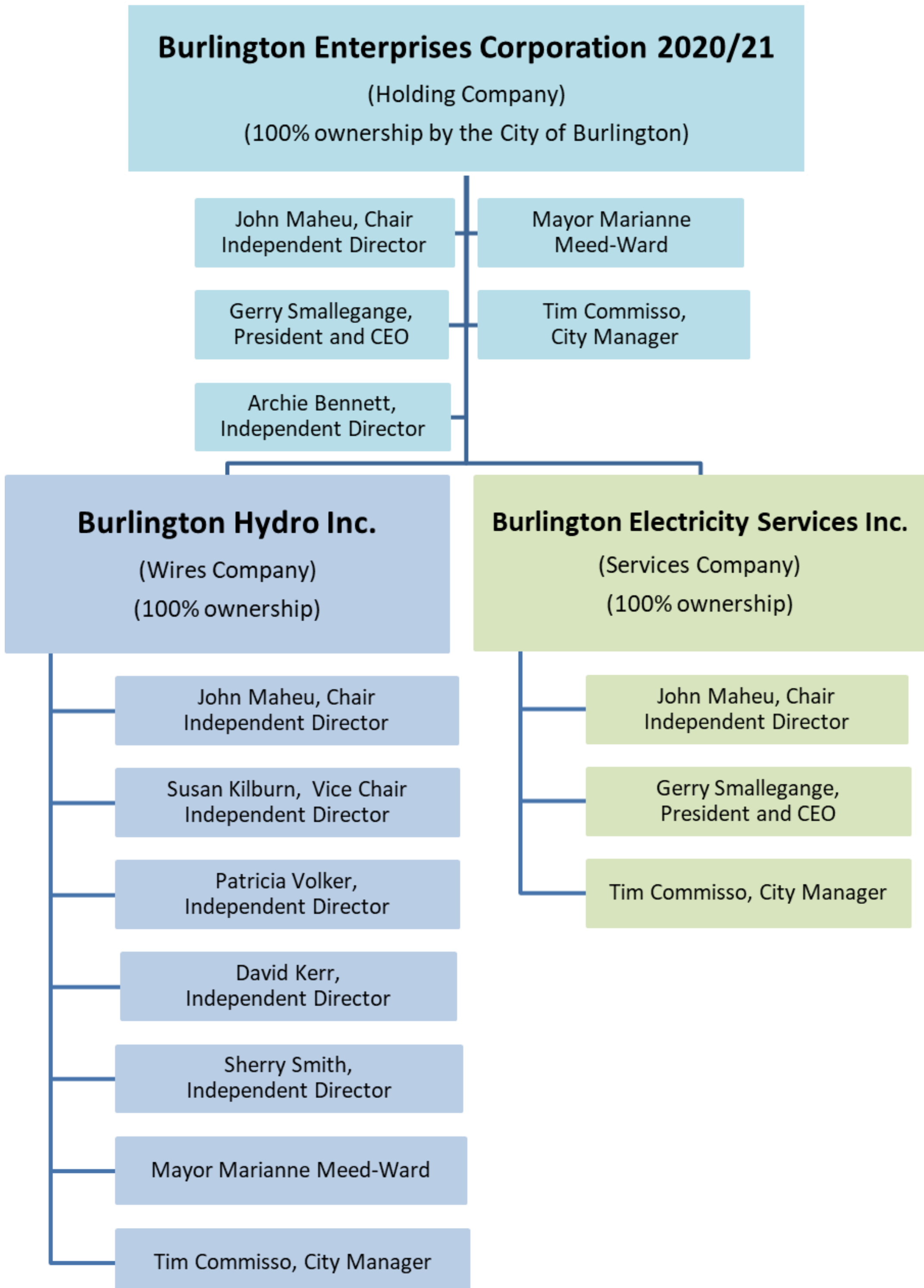
In late 2018, the OEB issued guidance for regulated utility governance, which included new mandatory reporting and record-keeping requirements for utilities. As a result of this guidance, the leadership team and Board brought recommended governance changes to City Council in June 2019 that would, if adopted, comply with the OEB utility governance model.

The overall operation of the corporation continues to perform as it always has, but with the following adjustments:

- The holding company, Burlington Hydro Electric Inc. (BHEI), has been renamed Burlington Enterprises Corporation (BEC);
- Independent (of the shareholder) Board members are appointed to Burlington Hydro Inc.;
- Board decision making and the majority of Board meetings take place through BHI (previously at the holding company); and,
- BEC will meet less frequently to approve dividends and approve the business plan/audit.

The governance framework is shown on the following page.

Governance Framework



Positioned for Success

Our Mission

To provide reliable, efficient and safe energy solutions to the community.

Our Vision

To be recognized as the leading energy solutions provider in Ontario by:

1. Ensuring a safe, reliable distribution service;
2. Delivering electricity at reasonable distribution rates;
3. Investing in new technology that could help reduce future distribution electricity costs;
4. Replacing aging infrastructure that is beyond its useful life;
5. Finding efficiencies and ways to find cost savings;
6. Upgrading the distribution system to better respond to and withstand the impact of adverse weather;
7. Providing quality customer service and enhanced communications; and,
8. Providing customers with conservation information and education as it relates to public electrical and powerline safety.

Our Core Values

Burlington Hydro Cares for People

We interact with customers, employees, the public, and our business partners with integrity and respect, and at all times act in a responsible and professional manner.

Burlington Hydro Cares for the Community

We take pride in making significant contributions to our community by helping to implement and contribute to the City's 'Climate Action Plan' and 'Climate Change Adaptation Plan', supporting local business development activities, and delivering important safety programs to our schools, among others.

Burlington Hydro Cares about Stewardship

We value the long term health and sustainability of Burlington Hydro and will assure availability of a future electricity supply that meets customer needs and growth. We value the community we serve and the environment in which we operate, managing environmental risks to eliminate or minimize adverse impacts associated with our businesses.

Burlington Hydro Cares about Performance

We value a fully integrated business model. We deliver superior products to our customers in a safe and efficient manner, striving for excellence and continuous improvement in all aspects of our business.

Burlington Hydro Cares about Shareholder Value

We create sustainable value for our shareholder by understanding and addressing customer needs, focusing on and promoting core business strengths, and pursuing appropriate business opportunities.

The Impact of COVID-19

At the time of writing the 2021 Business Plan, the province had entered Stage 3 of Ontario's re-opening and the measured re-opening of certain businesses, including the lifting of some social restrictions. The "normal" state of the 2021 business planning process has been impacted by the 2020 business landscape and the coronavirus pandemic.

We are planning how our work landscape might look once social and business restrictions are relaxed in the province and in our community. This is likely to represent a long process that extends well into 2021.

In the meantime, BHI will continue to manage the impact of the coronavirus by:

- Managing revenue losses as a result of lower customer demand and consumption, and bad debt associated with customer defaults; and,
- Managing expenditures to ensure business continuity and employee safety measures are in place (i.e. setting up a second control room, an additional off-site operations centre, protocols for working from home, office measures to ensure a safe work environment, etc.);

Just as our internal Pandemic Plan has taken a phased approach, so will our plan that brings us closer to a 'new normal' as more employees begin to return to the workplace and delayed projects are once again ramped up. When that might happen remains dependent on how provincial and local governments and health authorities determine the timing and approach to be taken in moving forward.

Ensuring the health and safety of customers and employees continues to be a priority

The designation as an "essential workplace" has allowed utilities, including Burlington Hydro, to continue to staff and structure their operations to ensure service continuity. As such, Burlington Hydro has remained committed to ensuring that the lights stay on and the distribution network is maintained – that our local hospital, essential services and the many people who are self-isolating or working from home can depend on the safe and reliable distribution of power.

Business continuity has been maintained across the organization, from IT to billing, to power restoration and maintenance activities, to customer service and communications and will continue into 2021. Some of the measures that will remain in place, include among others:

- Ensuring that Burlington Hydro's pandemic plan, policies, procedures, and communications are up-to-date and relevant;
- Working with our industry partners through the GridSmartCity network to share best practices and ensure our protocols are both current and thorough, for both internal and external purposes; and,
- Putting measures and protocols in place to ensure physical distancing in the office setting, as well as: air gapping of line, substation and control room technicians; and,
- Enhanced sanitization of office common spaces and work areas, as well as fleet vehicles.

The implementation of these, and other measures, has put Burlington Hydro in a strong position in terms of the health and safety aspects of our daily operations. Established protocols will continue to be monitored and updated as the Province moves through its phased re-opening into 2021.

COVID-19 financial repercussions and operational impacts on the business

The 2020/21 Budget has already been negatively impacted by the pandemic. As such, we are continuing to model different scenarios on Revenues and Net Income which will continue into 2021. As more data provides increasing clarity, we'll continue to revisit the scenarios and refine the forecast as required.

This may include taking measures to:

- Curtail discretionary operating expenses
- Reduce inventory levels, and
- Cut back on capital expenditures where feasible

It's important to note that the measures being taken in response to COVID-19 are temporary in nature and are not necessarily representative of expenditure levels in 2021 to 2025.

Themes that reflect our COVID-19 response:

1. Keep the lights on – by maintaining a safe and reliable distribution system.

2. Maintain measures in place to keep our workers and the public safe.

3. Support customers with financial hardship to pay electricity bills by offering payment options/arrangements and promoting assistance programs that they may qualify for (e.g. CEAP, LEAP, OESP).

4. Maintain business continuity across the organization: from IT, to billing and customer service, among others.

5. Ensure financial viability of the company.

Strategic Objectives

Burlington Hydro’s customer-centric approach is a central consideration of the company’s core strategic objectives.

1. RELIABILITY	• Ensure safe and reliable electricity distribution to customers
2. REASONABLE RATES	• Deliver electricity at reasonable distribution rates
3. NEW TECHNOLOGY	• Invest in new technology that could help reduce future distribution electricity costs
4. AGING INFRASTRUCTURE	• Replace deteriorated, aging infrastructure where warranted.
5. INTERNAL EFFICIENCIES	• Find internal efficiencies and ways to find cost savings
6. CUSTOMER SERVICE	• Provide high quality customer service and enhanced communications
7. SAFETY	• Provide comprehensive public safety awareness education/communications

Strategic Principles

Principle 1: Customer focus.

Principle 2: Operational effectiveness.

Principle 3: Public policy responsiveness.

Principle 4: Strong and sustainable financial performance.

BURLINGTON HYDRO SWOT Analysis

STRENGTHS

Strong Brand

- BHI is a trusted, valued asset which the shareholder and the general public are proud of.
- Burlington Hydro brand is recognized and well respected.
- Industry leadership in partnerships such as GridSmartCity Cooperative.
- Excellent customer service record – 96% Customer Satisfaction(2019)
- Extensive community involvement

Strong Management & Staff

- Strong senior management and board teams.
- Highly productive staff – 7 of 59 LDCs by customers/FTE
- Highly skilled and experienced staff
- Excellent Safety record
- Industry leadership in successful Conservation, Green Technology and Innovation
- Employees are proud and enjoy working for BHI.

Financial Strength and Stability

- BHI consistently and predictably meets goals, financial targets and industry benchmark statistics
- Access to adequate supply until 2035.

WEAKNESSES

Labour Challenges

- Resistance of some staff to accept and acknowledge changes in the electricity distribution marketplace
- Risk Management culture requires ongoing reinforcement
- Aging workforce, particularly in management, can create capability gaps as retirements accelerate
- Training, skills development and process documentation requires ongoing reinforcement

External Factors

- Financial impact of COVID-19, and increasing number of customer defaults
- Revenue is susceptible to weather, load forecasts, slow account base growth, economic conditions (weather risk is diminishing due to fixed rate design for residential customers).

Other

- Need for one-time capital expenditures (i.e. CIS, ERP)
- Focus on short term financial performance (fiscal year vs. long term)
- Large number of assets installed in 1980's at end of life and require replacement
- Some BHI assets are now (i) beyond economic repair (cost of maintenance exceeds cost of replacement), (ii) obsolete (parts not available and/or not supported by manufacturer); (iii) at or nearing end of useful life and (iv) in very poor or poor condition
- Some legacy systems are aging (up to 25 years) and require planned replacement
- Distribution revenue covers inflationary increases only for Capital and OM&A
- Termination of Conservation Programs diminishes marketing capabilities and customer touchpoints

OPPORTUNITIES

Productivity/Efficiency

- Continue to optimize layout of existing facility, consolidate surplus property (renovations more cost effective than new build).
- Continue to find solutions to deliver electricity at reasonable distribution rates
- Investments in new technology that could help reduce future distribution electricity costs
- Find more internal efficiencies and ways to find cost savings;
- Continue enhancement of quality customer service
- Allocation of capital to adopt new technology that will increase productivity.
- Productivity improvements through automation (outage management software, IVR, CIS, payroll, GIS, wireless inventory, just-in-time delivery, business intelligence, self-serve portals) and GridSmartCity purchasing co-operative
- Subcontract routine elements of services delivery system.

Attracting Talent

- Promote BHI as a great place to work and a well-managed company (Top 100 Employer – Hamilton-Niagara)
- Merger activities in the marketplace are creating a source of well-trained and capable recruits for BHI positions.

Branding/Self Promotion

- Build reputation and brand to customers through continued use of surveys and provision of information;
- Create strategies/actions to respond to customers' sensitivity to the cost of electricity; increasing dependence on functionality of electric and electronic devices; and growing expectations for instant communications on power related issues such as outages.

THREATS

Financial

- Financial impact of ongoing COVID-19 pandemic
- Costs escalating above the inflationary levels allowed for by the OEB.
- Uncertainty about outcome of Cost of Service application
- Expansion of Distributed Generation by non-utility entities can reduce distribution revenues and create stranded assets

Regulation/Policy

- Regulatory evolution may have unpredictable impact on distribution rates.
- Adverse change in provincial government policy.

Cyber Security

- Customer billing is more complex and has potential for greater cyber-risk
- Increased use of electronic communications increases security risks

People & Climate

- Risk of employee injury due to inexperience
- Shortage of qualified staff for Management and Control Room functions
- Increased frequency and intensity of severe climate events will impact reliability and safety of staff and public.

Board’s 2021 Prioritized Strategies

1. Mitigate COVID-19pandemic impacts with consideration given to curtailing discretionary spending.

2. Ensure program assistance/payment options for those struggling to pay their electricity bills are easily accessible.

3. Ensure that the most current procedures and measures are in place as per the direction of governmental health agencies and that employees and the public are kept safe.

4. Continue to seek out efficiencies and ways to find cost savings, including working collaboratively with GridSmartCity Cooperative partners to help achieve these ends.

5. Implement the new Customer Information System (CIS) – late 2020.

6. Successful cost of service application – submit October 2020 with process continuing into 2021.

Cost of Service Rate Filing

Filing Extension to October 2020 – For Rates 2021 to 2025

The process of bringing together Burlington Hydro's Cost of Service application was interrupted in the spring of 2020 due to COVID-19. As a result, BHI's filing deadline of August 2020 was extended to October 2020.

BHI sets its distribution rates under the Price Cap Incentive Rate ("IR") Setting - base rates are set through a Cost of Service process for the first year and rates for the following four years are adjusted by inflation less a stretch factor.

A Cost of Service (COS) application, scheduled to be filed by BHI in October 2020 for May 2021 rates, sets a price for a service based on the costs to provide it. The Ontario Energy Board (OEB) will approve the revenue for BHI's 2021 year based on the sum of: a prescribed rate of return on rate base (net fixed assets and working capital); operating expenses; depreciation; interest expense; and income tax. Distribution rates for the subsequent four years are limited to inflationary increases and as a result, the Cost of Service application will determine 5 years of distribution revenue.

The OEB will review the COS rate application through a public process. Documents are posted on the OEB's website and updated as the OEB reviews the application. Consumer groups and other affected groups (intervenors) may also take part in the process and provide comments. A series of clarification questions will be exchanged between the two parties – BHI and intervenors/OEB staff. A full hearing may also ensue. The process continues into 2021 in advance of the OEB's final decision on the application.

A successful COS outcome is critical to Burlington Hydro's success.

Application Objectives

- Incorporate customer interests and preferences
- Ensure all assets are operated, constructed and maintained in a condition which is safe for all employees, contractors and the public
- Demonstrate on-going continuous improvement while delivering on system reliability and quality objectives
- Demonstrate value for money
- Replace deteriorated aging infrastructure where warranted and invest in redundancy
- Address innovation and grid modernization
- Ensure reasonable distribution rates
- Effectively manage risk – financial, operational, cyber security, regulatory, obsolescence
- Ensure public policy responsiveness

Key aspects of a COS application are Customer Engagement, the Distribution System Plan (Capital) and Operating Expenses.

Customer Engagement

The OEB requires LDCs to incorporate customer needs and preferences in its COS application. BHI engaged Innovative Research Inc. to conduct the Customer Engagement for its COS application.

- Phase 1 of the Customer Engagement, completed at the end of June 2019, solicited preliminary feedback from customers (high-level values and preferences). A needs and preferences planning "placemat" to inform budgeting was created based on focus groups and telephone surveys.
- Phase 2 of the Customer Engagement solicited feedback on BHI's proposed capital and operating plans for 2021-2025. A comprehensive online workbook was launched in early 2020 to solicit customer feedback on specific capital and OM&A programs. A customer workshop was held for large commercial customers. Customers' needs and preferences were then summarized in a final report and BHI then modified its capital plans as necessary to incorporate customer preferences. BHI's corporate objectives were also factored in.

Distribution System Plan (DSP)

The OEB requires LDCs to file a Distribution System Plan in support of its COS application. BHI engaged Metsco Energy Solutions to assist with its DSP. BHI's DSP was finalized after the customer engagement process was complete. It includes:

- Asset related performance objectives
- Approach to lifecycle asset management and the management of asset-related operational and financial risk
- A plan for capital-related expenditures over a five-year forecast period (2021-2025) and the justification of those expenditures
- Planned investments for the development and implementation of the smart grid to support grid modernization and expenditures required by legislation

The 2021-2025 DSP addresses the replacement of a number of BHI's assets installed in the 1980s which are nearing end-of-life. To inform the DSP, BHI completed an Asset Condition Assessment and implemented program evaluation and project prioritization tools.

These tools assisted in objectively evaluating and prioritizing capital projects in alignment with customer preferences and BHI's corporate objectives.

Customer Engagement
Needs and Preferences Planning Placemat

What are customer needs?

The clear majority of Burlington Hydro residential and small business customers are satisfied with the current service they receive. When asked how Burlington Hydro can improve service, top responses were "nothing", followed by "lower or reduce rates".

	Residential	Small business (GS<50kW)
1st	Nothing	Nothing
2nd	*Lower or reduce rates*	*Lower or reduce rates*

What outcomes do customers prioritize?

Customers don't expect Burlington Hydro to just focus on one outcome. In fact, the majority of both residential and small business customers feel that the following outcomes are *extremely important*.

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates
- Investing in new technology that could help reduce future distribution electricity costs
- Replacing aging infrastructure that is beyond its useful life
- Finding internal efficiencies and ways to find cost savings
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather
- Providing quality customer service and enhanced communications
- Helping customers with conservation and cost saving

Among competing outcomes, *price*, *reliability*, and *finding internal cost efficiencies* are the top three priorities for both residential and small business customers. When ranked relative to other priorities, Burlington Hydro customers see price as the top outcome that the utility should focus on.

	Residential	Small business (GS<50kW)
Top Priority	Reasonable distribution rates	Reasonable distribution rates
2nd Priority	Ensuring reliability electrical service	Ensuring reliability electrical service
3rd Priority	Finding internal efficiencies and ways to find cost savings	Finding internal efficiencies and ways to find cost savings

What reliability outcomes do customers prioritize?

Residential and small business customers have the same priorities when it comes to reliability, however, in a different order. For residential customers, restoration times during extreme weather is number one, while for small business customers it is the number of outages.

	Residential	Small business (GS<50kW)
1st	Restoration times during extreme weather	Overall number of outages
2nd	Overall length of outages	Restoration times during extreme weather
3rd	Overall number of outages	Overall length of outages

What investment trade offs do customers value most?

While customers feel that Burlington Hydro should focus on delivering electricity at a reasonable rate, there is also a general willingness to invest in the grid.

The majority of residential and small business customers are willing to consider paying more to invest in maintaining reliability, equipping staff with equipment and IT systems, proactively investing in system capacity, and modernizing the grid knowing that it could eventually save money.

Small business customers are more likely to support investments in system capacity and grid modernization. Residential customers are largely divided when it comes to proactively investing in system capacity.

Replacing Aging Infrastructure (System Renewal)

The majority of residential and small business customers are supportive of Burlington Hydro making investments in aging infrastructure in order to maintain reliability, even if that results in small rate increases.

% of customers who say Burlington Hydro should invest what it takes to maintain reliability

	Residential	Small business (GS<50kW)
Invest to maintain reliability	64%	68%

Keeping the Business Running (General Plant)

The majority of residential and small business customers support Burlington Hydro making the necessary investments to ensure its staff have the equipment and IT systems that are needed to manage the system efficiently and reliably.

% of customers who say Burlington Hydro should make investments necessary in general plant

	Residential	Small business (GS<50kW)
Invest what is necessary	63%	64%

Proactive Investments in System Capacity (System Service)

Residential and small business customers are divided when it comes to investing in system capacity in order to ensure that customers in high growth areas do not experience a decrease in reliability.

A small majority of residential customers support these types of investments, the lowest level of support relative to any other investment category. Again, relative to other investments, small business customers are most likely to support investments in system capacity.

% of customers who say Burlington Hydro should proactively invest in system capacity

	Residential	Small business (GS<50kW)
Proactively invest in system capacity	56%	76%

Proactive Investments in Grid Modernization (New Technology)

The majority of residential and small business customers are supportive of Burlington Hydro proactively investing in modernizing the grid now, knowing it will cost more now, but could eventually save customers money down the road.

% of customers who say Burlington Hydro should proactively invest in modernizing the grid now

	Residential	Small business (GS<50kW)
Proactively invest in modernization	64%	72%

Customer Engagement Methodology

These findings are based on two telephone surveys conducted by *Innovative Research Group* among residential and GS<50kW customers.

- **Field Dates:** June 3 – 25, 2019
- **Sample Size:** n=506 residential and n=108 GS<50kW (unweighted)

Additional Information

For more information on using this document or customer engagement results, please contact:

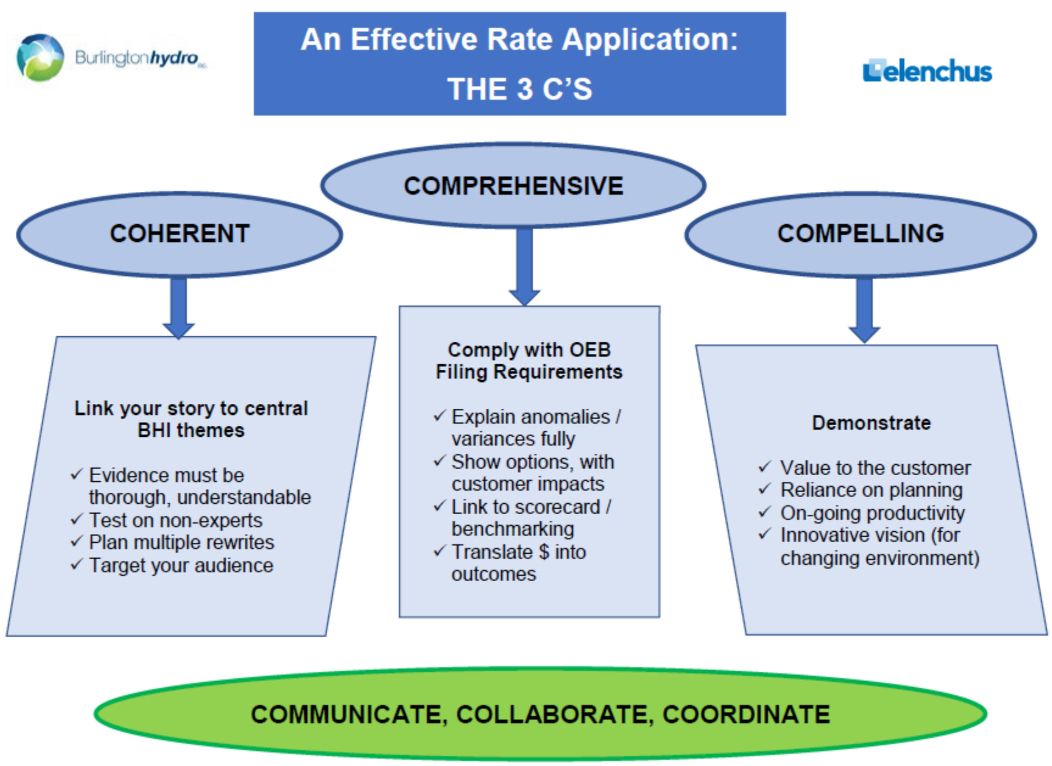
- **Sally Blackwell**, Director, Regulatory Affairs, Burlington Hydro
- **Julian Garas**, Senior Consultant, Innovative Research Group

Operating Expenses (Exhibit 4)

LDCs are required to include information in a COS application that summarizes Operating, Maintenance and Administration (OM&A) expenses, depreciation expense and taxes. These are collectively referred to as Operating Expenses and must include:

- Summary and Cost Driver Tables
- Program Delivery Costs with Variance Analyses
- Workforce Planning and Employee Compensation
- Shared Services and Corporate Cost Allocation
- Depreciation/Amortization/Depletion
- Taxes or Payments In Lieu of Taxes (PILs)
- Conservation and Demand Management

LDCs must discuss performance management and demonstrate continuous Improvement. In past decisions, the OEB has applied the "envelope" approach to determine OM&A for the cost of service year, represented by increasing an LDC's last year of actuals by "inflation + growth – productivity". Any one-time costs incurred in the last year of actuals are removed. The onus is on the LDC to justify any expenditure outside of inflation.



New Customer Information System (CIS)

A Customer Information System (CIS) is a key enabler of Customer Service and Billing capabilities for our customers. Burlington Hydro is replacing its current legacy CIS with a more advanced technology solution to streamline the integrated delivery of Customer Care and to minimize billing delays.

BHI reviewed alternative CIS solutions in the market and concluded on a Canadian software solution of choice in late 2018. Project Implementation was underway in early 2019 with a projected cutover to the new system in late 2020.

This investment includes:

- An integrated 24X7 online Customer Portal for convenient e-bill delivery;
- Immediate access to TOU consumption and related consumption alerts, as well as Account transaction history;
- An online 'Move In/Move Out' Smart Phone application that supports quick and easy moves from one location to another;
- Faster processing of field based electronic Customer Service Orders provides for more timely responses to Customer Service inquiries;

Timely deployment of CIS enhancements will be achieved in response to both customer needs and consumer driven public policy initiatives from the OEB.

BHI's new CIS investment facilitates continued business process streamlining, increased productivity and organizational effectiveness. It also eliminates the high cost of legacy software ownership related to modifications and annual maintenance.

Cyber Security

With continuous and rapid advances in technology, and the proliferation of knowledge via the Internet, utilities face a daunting challenge of ensuring the ongoing protection of their assets and information. No implementation of process or technology can guarantee a completely secure environment. Cyber risk can be monitored and managed, but not completely eliminated.

Wherever possible, BHI follows industry best practices in its efforts to protect and secure its assets and information. These protections include safeguarding the organization against loss, theft, corruption and/or misuse of its business information, defense against unauthorized access to corporate facilities and assets, and the protection of its systems from intrusions and malware. Audits of its cyber security systems by external specialists help ensure that the organization maintains an up to date and effective suite of mitigation measures and controls.

BHI works closely with the industry's Cyber Security Advisory Committee (CSAC) and the OEB to collaboratively evolve and advance the 'Ontario Cyber Security Framework' (OCSF). We continue to successfully implement this valuable framework as part of our comprehensive cyber security protection. In a typical year, the Burlington Hydro corporate infrastructure blocks millions of cyber related attempts from other countries to access BHI's assets for malicious purposes. Although these access attempts can be of an unauthorized "informational" nature, they still require the same interrogation vigilance of a "critical" attempt.

Diligent monitoring, analysis and protection against hacking, intrusions, ransomware attacks and other threats to our technical infrastructure is accomplished through the strategic implementation of managed security services partnerships, deployment of the latest cyber security tools and continuous improvement of our Information Security Management Program. This also includes coordination with key government agencies such as the Canadian Centre for Cyber Security and the Canadian Cyber Threat Exchange.

Burlington Hydro continues to maintain a vigilant focus on Cyber Security risk to ensure continued confidentiality, integrity and availability of its business assets, processes and information systems.

2021 Action Plans

A. Responsible Financial Management (3 Strategies)

STRATEGY 1 - COST OPTIMIZATION

LOWER OPERATING AND MAINTENANCE COSTS

1) Grow the shared services model with GridSmartCity LDC members to collectively procure or deliver services and materials more cost efficiently. This could include services/resources with respect to: benefits; insurance; inventory (wire, transformers); fleet outsourcing; service outsourcing; etc.
2) Continue to review and re-visit workflow processes and standards to eliminate redundancy and chokepoints.
3) Continue to create integrated systems to support redesigned workflows.
4) Monitor and measure BHI performance against goals and industry benchmarks.
5) Develop plans to improve operating costs:
   - Strategic use of line of credit
   - Migrate customers to e-billing using incentives
   - Consider increasing account payable cycle
   - Consider migration to semi-monthly payroll
6) Prepare and submit a successful Cost of Service application.

STRATEGY 2 – MITIGATION

FINANCIAL MITIGATION STRATEGIES

1) Maintain optimal Asset Management plans
2) Implement Smart Subcontractor Management
3) Prepare local grid for higher demand
4) Prepare and submit a successful Cost of Service application (2021-25 rates)

STRATEGY 3 – RISKS

FINANCIAL RISKS/OPPORTUNITY COMMUNICATIONS

1) Ensure Board Members and Senior Staff are well apprised of financial risks/opportunities tied to organizational threats and weaknesses.

B. Internal Processes – Operational Effectiveness (4 Strategies)

STRATEGY 1 – ORGANIZATIONAL DESIGN IMPROVEMENTS

ORGANIZATIONAL

1) Continue Staff Training and Development Plan
2) Implement functional staff cross-training and improve process documentation to improve capability redundancy among staff.
3) Migrate towards the "right" organizational structure to support current operational requirements
4) Manage employee attrition, specifically retirements
5) Use subcontracting where appropriate with adequate "cross-training" to ensure that staff can assume sub-contracted duties if required
6) Develop or enhance recruitment strategies targeting underrepresented demographics
7) Ensure succession plans are in place for key positions

STRATEGY 2 – INFORMATION TECHNOLOGY

ACTION PLAN – INFORMATION TECHNOLOGY (BHI)

1) Strengthen cyber security processes to manage increasing risk due of cyber-attacks and disruptions, and to ensure compliance with the OEB's Cyber Security Framework
2) Continue redesign of workflow processes and update standards
3) Continue to create integrated systems to support redesigned workflows
4) Successfully integrate and implement new JOMAR Customer Information System (CIS)
5) Continue to expand use of FileNexus system to digitize paper files – beyond HR and Customer Service.

STRATEGY 3 – FACILITY

ACTION PLAN – FACILITY (BHI)

1) Adjust space configuration to improve work and people flow patterns
2) Develop economic model to evaluate racking storage systems
3) Complete office renovations to refresh and improve work spaces, meeting rooms and service areas. Prioritize as budgeted.

STRATEGY 4 – DISTRIBUTION SYSTEM PRIORITIES AND NEEDS

ACTION PLAN – INFRASTRUCTURE

1) Update the Distribution System Plan to shape future capital spending plan, including infrastructure and to support a successful Cost of Service (COS) application.
2) Address assets in very poor/poor health by replacing deteriorated, aging infrastructure where warranted

C. Customer – Customer Satisfaction (3 Strategies)

STRATEGY 1 – CUSTOMER SATISFACTION

ACTION PLAN – ENHANCE CUSTOMER SATISFACTION

1) Ensure customers are well informed of measures being taken during COVID-19 – from our commitment to keep the lights on, to programs and payment options available to help those struggling to pay their electricity bill
2) Ensure customers are well informed of events and changes in the Ontario electricity sector
3) Stress BHI's cost effective delivery of those portions of the electricity sector within our control
4) Conduct annual customer satisfaction surveys and implement key recommendations within our control
5) Ensure customer understanding of BHI Value Proposition to community – "Shine" Campaign

STRATEGY 2 – CORPORATE COMMUNICATIONS

ACTION PLAN – CUSTOMER COMMUNICAITONS

1) Build on communications strategy to include:
    a. Profiles of Successes and cost effective electricity distribution
    b. GridSmartCity and BHI Brand Building
    c. Promotion of BHI as a "Great Place to Work," "Employer of Choice," and "Safe Employer"

STRATEGY 3 – CLIMATE ACTION PLAN

ACTION PLAN – CLIMATE ACTION PLAN

1) Support transition from the City of Burlington's Community Energy Plan to a Climate Action Plan and the development of a Climate Change Adaptation Plan.
2) Support implementation of said plans and provide leadership/expertise as required.

D. Learning and Growth – Employer of Choice (2 Strategies)

STRATEGY 1 – STRENGTHEN EMPLOYEE CULTURE

ACTION PLAN – STAFF SATISFACTION

1) Strengthen culture through regular communications and feedback
2) Enhance employee engagement strategy

STRATEGY 2 – HEALTH AND SAFETY

ACTION PLAN – SAFETY EXCELLENCE

1) Take steps to participate in a recognized Safety Management System that promotes health and safety excellence, and takes us beyond IHSA Zero Quest program.
2) Implement ongoing public safety campaign in response to ESA Safety Survey
3) Meet safety metric Re: OEB Scorecard
4) Run ESA Contractor Safety Program

LDC Scorecard

Burlington Hydro has a business culture that promotes continuous adjustment and improvement to ensure it delivers value in the services it provides to its customers.

The LDC Scorecard reports performance metrics for each electricity utility in Ontario, including Burlington Hydro. The scorecard provides data for 20 specific measures in the following four key areas of performance:

- Customer focus
- Operational effectiveness
- Public policy and responsiveness
- Financial performance

BHI strives to achieve excellence and continuous improvement across all aspects of its business. As such, the company successfully met all of its performance targets on its 2019 LDC Scorecard (the latest available scorecard).

The Scorecard is shown on the proceeding page.

Scorecard - Burlington Hydro Inc.

9/11/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		98.30%	96.70%	97.72%	98.31%	100.00%	↑	90.00%	
		Scheduled Appointments Met On Time		99.60%	100.00%	100.00%	99.81%	100.00%	↑	90.00%	
		Telephone Calls Answered On Time		75.60%	74.70%	80.13%	83.28%	81.43%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		94%	92	96	91	82.4%			
		Billing Accuracy		99.95%	99.97%	99.96%	99.76%	99.97%	↓	98.00%	
		Customer Satisfaction Survey Results		90%	86	92	94	96%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		81.00%	81.00%	84.00%	84.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.18	0.98	1.04	1.44	1.05	↑		1.09
		Average Number of Times that Power to a Customer is Interrupted [2]		0.71	0.60	0.64	0.85	0.75	↓		1.07
	Asset Management	Distribution System Plan Implementation Progress		On Track	OnTrack	On Track	On Track	n/a			
	Cost Control	Efficiency Assessment		3	2	2	2	2			
		Total Cost per Customer [3]		$616	$620	$608	$627	$661			
		Total Cost per Km of Line [3]		$26,730	$27,518	$26,606	$27,766	$29,293			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		12.75%	26.39%	62.56%	81.00%	96.00%			99.04 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	97.87%	97.37%	100.00%	↓	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		2.46	2.51	2.25	2.52	2.07			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.81	0.78	0.75	0.80	0.75			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%			
			Achieved	9.20%	7.98%	6.69%	6.43%	7.16%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the 2015-2020 Conservation First Framework. 2018 results are based on the IESO's unverified savings values contained in the March 2019 Participation and Cost Report.

Legend:
5-year trend: ↑ up ↓ down → flat
Current year: target met, target not met

Other Considerations

Government Actions/Orders Issued in Response to COVID-19 Pandemic

- A temporary 45-day **emergency rate** relief on time-of-use (TOU) electricity prices was announced by the Government of Ontario in March. Households, farms and small businesses paying TOU electricity rates would be charged **off-peak rates at 10.1 cents per kWh**, 24 hours a day, 7 days a week, effective March 24, 2020. The off peak rate was extended until April 30.

- Beginning June 1, 2020, customers on TOU rates were billed a **new fixed COVID-19 Recovery Rate of 12.8 cents** per kWh until October 31, 2020.

- The **ban on winter electricity disconnections** (Nov 15 to Apr 30) was extended to July 31, 2020, for all residential and small business customers. The measure was in response to financial hardships resulting from the COVID-19 pandemic. Burlington Hydro offered payment terms/options for those customers struggling to pay their bill. In addition, several assistance programs were in place to help those facing financial challenges.

- The Ontario government implemented an **Emergency Order (EO) on May 1, 2020 to defer a portion of the Global Adjustment (GA)** charges for industrial and commercial electricity consumers that do not participate in the Regulated Price Plan (RPP). The GA rate for smaller industrial and commercial consumers (i.e., Class B) has been set at $115 per megawatt-hour. Large industrial and commercial consumers (i.e. Class A) receive the same percentage reduction in GA charges as Class B consumers. Industrial and commercial electricity consumers automatically saw this relief reflected on their bills.

- $9 million for the **COVID-19 Energy Assistance Program (CEAP)** was provided to support residential customers struggling to pay their energy bills during the pandemic. CEAP provides one-time payments to consumers to help pay down any electricity bill debt incurred over the COVID-19 period. Applications were available on the BHI website, beginning July 13, 2020. Burlington Hydro was allocated $63,235

- $8 million for the **COVID-19 Energy Assistance Program for Small Business (CEAP-SB)** provides support to businesses struggling with bill payments as a result of the outbreak. Applications were available on the BHI website, beginning August 31, 2020. Burlington Hydro was allocated $59,455.

- **Effective November 1, 2020**, the government will introduce customer choice for Regulated Price Plan (RPP) customers who currently pay time-of-use prices (TOU). Customers will be able to choose a plan that best suits their household and lifestyle with the **option of either TOU electricity rates or tiered pricing**, which provides a set rate for electricity up to a certain level of consumption. Although announced, this option had yet to be implemented at the time the Business Plan was written.

Bill 87

In May 2019, the Ontario Legislature passed *Fixing the Hydro Mess Act, 2019*. The legislation (formerly Bill 87) passed without any amendments of note to LDCs.

The legislation continues to impact LDCs and the electricity industry by:

- Centralizing streamlined electricity conservation programs at the Independent Electricity System Operator (IESO);
- Overhauling the OEB to make the regulatory system more efficient and accountable while continuing to protect consumers;
- Holding residential electricity bills to the rate of inflation;
- Winding down the Fair Hydro Plan;
- Prescribes an on-bill rebate on consumer bills to replace the Fair Hydro Plan.

The EDA continues to address the LDC sector's involvement in bill presentment changes and regulation. On OEB modernization, the EDA is examining the full regulatory burden reduction potential for the regulator under its new governance model.

Four Industry Policy Principles (as advocated by the EDA)

The Electricity Distributors Association (EDA) emphasizes 4 policy principles Ontario's policymakers must consider to enhance Ontario's competitiveness and ensure a safe, reliable, affordable flow of power to homes and businesses across our province.

Keep the Customer First

- Across our province, hydro customers demand greater value and more control over their electricity usage and bills.
- Customers are showing a growing interest in distributed energy, and want more choice to self-generate renewable power.
- Local hydro utilities are best positioned to extend existing relationships and manage local energy services for customers, while protecting customers' privacy and overall interests.

Cut Through Red Tape

- Ontario's local hydro utilities continue to leverage leading edge technologies and build their capacity for distributed energy resources.
- To sustain this momentum, the province's regulatory structure must be flexible to allow local hydro utilities to adapt to rapidly evolving market conditions.
- A modern, competitive regulatory framework will minimize red tape and facilitate opportunities

Drive Local Hydro Innovation Forward

- Ontario can drive innovation by helping local hydro utilities assume a critical function in the province’s energy transition.
- Going forward, local hydro utilities will enable, control and integrate electricity generation and storage from a variety of small grid connected devices, also known as distributed energy resources.
- Local hydro utilities will continue to work with community members and businesses to maximize cost savings, choice and convenience for customers.

Respect Community Decision-Making

- Ontario communities have local autonomy to explore transaction options for their local hydro utility.
- To date, some municipal shareholders have decided to sell, a few have acquired utilities, others have opted to merge and many have chosen to stand alone.
- Communities must continue to have autonomy to make their own decisions within a flexible environment about the future of their local hydro.

Glossary of Terms

AFI	Advanced Metering Infrastructure
AGM	Annual General Meeting
BEC	Burlington Enterprises Corp.
BESI	Burlington Electricity Services
BHEI	Burlington Hydro Electric Inc.
BHI	Burlington Hydro Inc.
CEP	Community Energy Plan
CEAP	COVID-19 Energy Assistance Program
COS	Cost of Service
CIS	Customer Information System
CPI	Consumer Price Index
DER	Distributed Energy Resources
ESA	Electrical Safety Authority
EVs	Electric Vehicles
EHRC	Electricity Human Resources Canada
FIT	Feed-in Tariff (>10 kW)
FTE	Full Time Employee
GIS	Geographic Information System
GPS	Geographic Positioning System
GSC	GridSmartCity
HON	Hydro One Networks
HVAC	Heating, Ventilation and Air Conditioning
ICE	Integrated Community Energy
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standard
IRM	Incentive Regulation Mechanism
IVR	Interactive Voice Response
IT	Information Technology
kW	Kilowatt (measure of demand)
kWh	Kilowatt Hour (measure of consumption)
LDC	Local Distribution Company
LEAP	Low Income Energy Assistance Program
microFIT	Micro Feed-in Tariff (<10 kW)
NRCan	Natural Resources Canada
OEB	Ontario Energy Board
OESP	Ontario Electricity Support Program
OM&A	Operations, Maintenance and Administration
OPA	Ontario Power Authority
PBR	Performance Based Regulation
ROE	Return on Equity
RSVA	Retail Settlement Variance Account
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQI	Service Quality Indicator
TS	Transformer Station
UPS	Uninterruptible Power Supply
VPN	Virtual Private Network

NOTES

Burlington**hydro** inc.

2021 PRO FORMA & FINANCIAL STATEMENTS

PART B

BURLINGTON HYDRO INC

Confidential and Commercially Sensitive

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BURLINGTON HYDRO INC.

2020 UPDATE FINANCIAL HIGHLIGHTS

Income Before Tax is forecast at **$3.7M** for 2020**,** a **$785k positive variance to budget**.   While Distribution Revenues are forecast to fall to 97% of budget, positive variances in Other Operating Revenue and reductions to Operations & Maintenance costs will offset the Distribution Revenue shortfall.

Net Income After Tax is forecast at **$3.3M**, a **$696k positive variance to budget**.

Review of Earnings Statement :

(000's)			2020 Budget		2020 Update	+ve (-ve) Variance
Distribution Revenue	(1)		$32,273		$31,325	($948)
Other Operating Revenue	(2)		2,479		3,417	938
Operating Expenses	(3)					
- Operating & Maintenance		10,495		9,608		
- Billing & Collecting		2,904		3,012		
- Administration (incl prop tax)		8,293	21,692	8,300	20,920	772
Depreciation	(4)		7,216		7,122	94
Net Finance Costs	(5)		2,918		2,989	-71
Income Before Tax			$2,926		$3,711	$785
Income Taxes			336		427	-90
Net Income After Tax			$2,589		$3,285	$696

(1) *"Distribution Revenue" is forecast to fall below budget by **$948k ($31.3M vs $32.3M)**.*

- Both system wide kWh (energy) and kW (demand) approached budgeted levels, however, the split of kWh between the rate classes differed from budget due to the impacts of CV-19. Local distribution rates/revenues are calculated differently depending on customer class:
  - Residential Class – distribution revenues are based on a fixed monthly charge
    - kWh consumption by the Residential class increased significantly during the CV-19 shutdown in Q2 and Q3 as "stay at home" orders resulted in high usage. This usage, however, had no positive impact on Distribution Revenue as the Residential Class pays a fixed monthly charge for local distribution regardless of actual usage.

- Small Commercial Class – distribution revenues are based on both a fixed monthly charge and a variable rate calculated based on the amount of kWh consumed.
    - kWh consumption by the Small Commercial sector fell significantly in Q2 and Q3 as a result of CV-19 closures and this had the most significant impact on the decrease in the utilities Distribution Revenue.
- Large Commercial, Industrial & Institutional (ICI) class – distribution revenues are based on both a fixed monthly charge and a variable rate calculated on peak kW for the month
    - The ICI customer class peak demand was impacted in Q2 by CV-19 shutdowns.

(2) *<u>"Other Operating Revenue" is forecast to exceed budget by $938k</u>* ***<u>($3.4M vs $2.5M).</u>***

- "Other Operating Revenue" includes the following major categories; Late Payment Charges, Region Water Billing services for BESI, Amortization of Contributed Capital funds and a Miscellaneous category. The "Miscellaneous" category is expected to have the following positive variances:
    - $366k – With the start of the Metrolinx Go Transit electrification project, we instituted a material handling charge to assist in recovery of BHI staff time and resources deployed for this project.
    - $108k – The BHI contractor assisting with the Metrolinx project uses the BHI yard to coordinate their resources and materials. We have implemented a site mobilization charge for this usage.
    - $491k – While the OEB has prohibited LDC's from charging collection fees, they have permitted LDC's to record these fees as though being charged, for eventual disposition at rebasing. This represents an accounting entry only to track revenues owed. Cash flow will be positively impacted when this amount is included for recovery at rebasing.

(3) *<u>"Operating Expenses" are forecast to be under budget by</u>* ***<u>$772k ($20.9M vs. $21.7M).</u>***

- "Operations & Maintenance Department (Control/Stations/Meters/Distribution)" costs are forecast to fall below budget by $887k.
    - $500k – Trades staff have been deployed to the Metrolinx project which are recoverable costs.
    - $185k – Tree Trimming Contract was tendered in 2020 and came in below budget.
    - $100k – reduced overtime costs

- "Billing & Collecting (Billing Dept, Call Centre, Meter Reading)" costs are forecast to increase by $108k:
    - $100k – Increase in bad debt allowance to recognize impacts of CV-19.

- "Administration Department (Executive, Human Resources, IT, Purchasing, Regulatory, Safety, Communications, Accounting, Board of Directors)" costs are forecast to meet budget.

(4) *<u>"Depreciation Expense" is forecast to be slightly under budget by</u>* ***<u>$94k ($7.1M vs. $7.2M).</u>***

(5) *"Net Finance Costs" forecast to exceed budget by **$71k ($3.0M vs. $2.9M).***

- Variance is due to lower cash balances and higher use of operating line of credit as CV-19 negatively impacted aging of receivables.

Capex *is forecast to be under budget by **$390k ($9.9M vs $10.3M).***

	2020 Budget	2020 Update
Sustaining Capex	$9,915	$9,525
Buybacks of Developer Subdivision Assets	350	350
	$10,265	$9,875

Capital expenditures are forecast below budget due to the following items:

- Sustaining Capex;
  - ($857k) – Distribution Projects delays were driven by the deferral of the North East Burlington Egress project to 2022.
  - ($180k) – Substation Equipment : deferred replacement of relays and breakers until 2021.
  - ($256) – Meters : lower than anticipated suite metering conversions in 2020.
  - ($104) – 1340 Brant Building : deferred Control Room upgrades and perimeter fence access improvements to 2021/2022.
  - +$1,024k – Computer Hardware/Software : GIS replacement took place in Jan 2020 due to existing software no longer being supported. Increase in costs of new CIS due to changes required by the new OEB regulatory requirements as well as unplanned delays as a result of CV-19.

2021 BUDGET FINANCIAL HIGHLIGHTS

A. *Highlights of this year's Operating and Capital Budgets:*

Income Before Tax is budgeted at $4.7M for 2021 with Distribution Revenues expected to increase by $3.8M from the 2020 Update.

Net Income After Tax is budgeted at $4.2M, an increase of $875k from the 2020 Update.

(000's)		2020 Update		2021 Budget	Change
Distribition Revenue		$ 31,325		$ 35,084	$ 3,759
Other Operating Revenue		3,417		3,468	51
Total Revenue		34,742		38,552	3,810
Operating Expenses					
- Operating & Maintenance	9,608		10,755		
- Billing & Collecting	3,012		3,123		
- Administration (incl prop tax)	8,300	20,920	9,269	23,147	2,227
Depreciation		7,122		8,055	933
Net Finance Costs		2,989		2,649	(340)
Income Before Tax		$ 3,711		$ 4,701	$ 990
Income Taxes		427		541	115
Net Income After Tax		$ 3,285		$ 4,160	$ 875

i. __REGULATORY BUDGET INPUTS__

- **Deemed Interest Rate on City Promissory Note reduced in 2021:**
  The deemed interest rate on the Shareholder Note was set at 4.88% at the 2014 Rebase Application and will be reset by the OEB during the 2021 Rebase Application. The new rate will become effective May 1 2021. The 2021 budget uses the most recent rate of 3.21%.

- **Leverage:**
  The OEB deemed debt/equity capital structure for LDC's is set at 60/40 of the utilities approved rate base. BHI's Rate Base for 2021 is forecast at $148MM which would permit a debt position for rate setting purposes of $89M.

  BHI's forecasted outstanding total debt at year end 2021 is within the OEB limit and continues to provide flexibility to increase long-term borrowings as needed.

Lender covenants limit Total debt/Total capital to .6:1. At forecasted year end 2021, Total debt/Total Capital would come in at under .5:1.

- **<u>New Rates will be effective retroactive to May 1, 2021 (implemented July 1, 2021) :</u>**
  2021 represents a Rebase Year for BHI. Rate setting under a Rebase Year is a full application to the OEB reviewing both OM&A costs and capital budgets.

ii. ***<u>2021 DISTRIBUTION REVENUE:</u>***

2021 Distribution Revenues will be set by the Rebase Application being submitted in October 2020.

- **<u>Distribution Rate Effective Dates:</u>**
  2021 Distribution Revenue is based on current 2020 Rates for the 4 months of Jan 1-April 30/21 and on forecasted 2021 Rates for the 8 months of May 1 – Dec 31/21.

- **<u>Consumption/Demand/Customer Forecasts:</u>**
  The forecast for 2021 energy (kWh), load (kW) and # of customers is based on Elenchus Research & Associates load forecast study which has been submitted with the Rate Rebase application.
  The BHI 2021 forecast is consistent with the load forecast inputs used for the Rate Application.

- **<u>Distribution Revenue:</u>**
  2021 revenues are forecast to increase by $3.8M over the 2020 Update based on customer growth, forecasts of kWh & kW, and LRAM (lost revenue adjustment mechanism). The majority of the increase is due to the reset of distribution rates upon rebasing.
  The LRAM adjustment being an OEB mechanism to allow utilities to recover lost revenues that are directly attributable to Conservation and Demand initiatives.

iii. ***<u>OTHER OPERATING REVENUE:</u>***

Other Operating Revenues include Late Payment Penalty Revenue, Billing Service Revenue and Miscellaneous Revenues such as pole rental income, control room service revenue and occupancy change charges.

The accounting entry, Deferred Revenue, is also included which records the amortization of the Balance Sheet liability account – “Deferred Revenue Capital Contributions”.

(000's)		2020 Update	2021 Budget	Change
Late Payments	(1)	$ 286	$ 299	$13
BESI Billing Services	(2)	401	403	2
Deferred Revenue	(3)	743	1,199	456
Miscellaneous	(4)	1,987	1,567	-420
		$ 3,417	$ 3,468	$51

(1) The 2021 budget reflects the average of our past 3 year historic experience in Late Payments adjusted for customer growth.

(2) Billing Service Revenue relates to the inter-company charges from BHI to BESI for staff and IT services enabling BESI to deliver water billing services to the Region of Halton.

(3) Deferred Revenue reflects IFRS accounting treatment for the receipt of capital contributions for built projects. Capital Contributions are received from customers for different capital projects according to the BHI Conditions of Service. Contributions received are recorded in both PP&E assets and as a Deferred Revenue liability on the Balance Sheet. The Deferred Revenue is amortized and recorded on the P&L over the life of the asset while an equal and offsetting depreciation expense related to the PP&E asset also gets reflected on the P&L. The result being no “bottom line” impact to the P&L. The year over year increase is a reflection of the volume of infrastructure build taking place and the level of capital contributions being received.

(4) Miscellaneous Revenues forecast for 2021 are below the levels of 2020. The $420k decrease occurs due to the following items:
   - $327k is due to the elimination of “Collection Charges” from LDC approved service fees. The OEB eliminated Collection Charges in 2019, but permitted LDC’s to track the lost revenue and recover from rates at their next Rebase Application. As BHI Rebase rates are effective May 1, 2021, only 4 months of Collection Charge fees are recorded in Misc Revenues for 2021.
   - $108k is due to the end of the Site Mobilization Fee being charged to our Metrolinx contractor for their use of the BHI yard and facilities.

iv. ***<u>OPERATING EXPENDITURES:</u>***

Operating Expenses prior to depreciation are forecast at $23.1M for 2021, an increase of $2.2M over the 2020 Update of $20.9M.

- O&M Department (Control Room/Stations/Meters/Distribution/Engineering) expenses increase by $1.1M (+11.9%)

- Billing & Collecting Department (Billing/Call Center/Meter Reading) expenses increase by $111k (+3.7%)
- Administration Department (Executive/Accounting/Purchasing/HR/Communications/Safety/Regulatory/Purchasing) expenses increase by $963k (+12.1%)
- Municipal tax increases by $6k (+1.8%)

Operating Expenses (000's)				
	2020	**2021**		
	Update	**Budget**	**Change**	
Operations & Mntce	9,608	10,755	1,147	11.9%
Billing & Collecting	3,012	3,123	111	3.7%
Administration	7,964	8,927	963	12.1%
	20,584	22,805	2,221	10.8%
Municipal Tax	336	342	6	1.8%
Total OM&A	$ 20,920	$ 23,147	$ 2,227	10.6%

Depreciation (000's)	**2020**	**2021**		
	Update	**Budget**	**Change**	
Depreciation	7,122	8,055	933	13.1%
Total Operating Expenses	$ 28,042	$ 31,202	$ 3,160	11.3%

Depreciation:
The increase in depreciation expense is a function of both the size of the capital budget dollars and the nature of the capital additions, which depreciate at differing rates.

The following comments relate to the 2021 Budget variances in the OM&A costs:

Operations & Maintenance Departments: $1.1M increase over 2020 Update:

1. Increase in annual tree trimming costs + $225k
   - Annual tree trimming is completed in 3 year cycles. The 2021 cycle is a larger treed area which results in increased costs.
2. Increase in labour costs + $545k
   - Trades labour costs were low in 2020 as crews were redeployed to work on the overhead phases of the billable Metrolinx electrification project. These trades employees will return to maintenance work in 2021.
3. Increase in allocation of Eng Dept costs + $473k
   - Eng Dept costs are allocated to Operating & Maintenance departments as well as capital projects. With the lower O&M costs in 2020, more of the Eng

Dept costs were allocated to capital vs O&M. In 2021, this allocation returns to a historic norm resulting in higher allocation of the Eng Dept costs to O&M.

4. Increase in overtime costs + $105k
   - 2020 saw below average storm activity resulting in lower overtime costs. 2021 was budgeted with the historic average for overtime.

Billing & Collecting Departments: $111k increase over 2020 Update:

5. Effective May 1, 2020, the incremental mailing and postage costs of monthly vs bi-monthly billing will be expensed rather than tracked in a Balance Sheet Variance account.

Administration Departments: $963k increase over 2020 Update:

6. Engineering Succession Planning +$150k.
7. Salary and Benefits HR positions + $200k
   - Hired new Director of People & Culture in Q3 2020 and new HR & P/R position in Q4 2020. Full year salary and benefits budgeted in 2021. Hires are for succession planning and payroll back-up.
8. Salary and Benefits Facilities Manager + $90k
   - New position to be filled Q4 2020. Full year salary and benefits budgeted in 2021. Elimination of a Locates position in Q1 2020 (outsourced) provides the opportunity to hire a Facilities manager.
9. Rate Rebasing costs + $176k
   - Costs associated with the Rebasing application shifted from 2020 to 2021 due to filing delays associated with Covid-19.
10. OEB Regulatory costs + $96k
    - Costs are driven by the OEB's annual assessment fees. These costs are recoverable in rates.
11. Salary & Benefits Senior Capital Financial Analyst + $75k
    - Position filled in Q3 2020. Full year salary and benefits budgeted in 2021. Position was created to facilitate BHI's capex planning and monitoring, including risk identification and corrective measures to bring capex on budget and on time.
12. Salary & Benefits Communications Assistant + $30k
    - Position filled in Q3 2020. Full year salary and benefits budgeted in 2021.
13. Safety Incentive program + $35k
    - Recognition of "no lost time" and the successful implementation of the WSIB Health & Safety Excellence program.
14. Safety Campaigns incl consulting costs +$40k
    - Public safety campaign costs to educate the public and meet regulatory requirements.
15. Union costs for collective bargaining +$20k
    - New collective agreement to be negotiated in 2021.
16. Customer Engagement Open House + $20k

- A community open house is planned to celebrate BHI's 75th anniversary. This event was postponed from 2020 due to the Covid-19 pandemic,

v. ***LONG TERM DEBT:***

An additional $10M of long-term debt is planned for 2021. This debt will be used to assist in financing the 2021 capital program as well as replenish working capital that has been drawn down funding the past three year's capital programs.

Ratio	Lender	Covenant	2020 Update	2021 Budget
DSR	TD & IO	1.3	2.6	2.6
Total Debt/Total Capital	TD	0.6	0.43	0.45
Debt/Total Assets	IO	0.6	0.29	0.28
Interest Coverage	n/a	n/a	4.4	5.8

EXISTING long-term debt:

Infrastructure Ontario Loan #1 - $10M drawn March 2011 with a 15-year amortization at a fixed rate of 4.51% maturing 2026. Blended principal and interest payments are due monthly.
The loan assisted with financing the Smart Meter and overall capital program.
Outstanding at year end 2021 will be $3.5M.

Infrastructure Ontario Loan # 2 – $8M drawn March 2013 with a 25-year amortization at a fixed rate of 4.02% maturing 2038. Blended principal and interest payments are due monthly.
The loan assisted with financing the Hydro 1 Transformer Station capital contributions and the overall capital program.
Outstanding at year end 2021 will be $6.1M.

Infrastructure Ontario Loan # 3 – $7M drawn December 15 2018 with a 15-year amortization and a fixed rate of 3.63% maturing 2033. The loan matches long-term funding against BHI capital expenditures including the true-up payment for the Tremaine transformer station and the two Tremaine breakers.
Outstanding at year end 2021 will be $5.9M.

Shareholder Promissory Note:

The 2021 budget and forecast assume 3.21% as the OEB deemed rate for non-third-party debt beginning May 1, 2020 vs the existing 4.88% rate. This is the most recent rate used by the OEB for utilities that rebased in 2020. This results in a reduction in interest expense of $536k in 2021. The actual rate will be set with the 2021 Rebase application.

Short-term Debt with TD Bank:

The forecast also includes the costs of maintaining a $20M operating line of credit for working capital needs and an $18M letter of credit facility to cover prudential requirements related to the monthly power bill with the IESO.

vi. ***Payment-in-lieu of Tax (PIL's):***

For 2021, enacted tax rates apply.

vii. ***NET INCOME:***

Net Income after tax is forecast at $4.2M for 2021.

viii. ***DIVIDENDS:***

Dividends forecast for 2021 are $2.05M.

ix. ***CASH FLOW***

The 10 year time horizon forecasts additional borrowings of $56M over the forecast time horizon with the new debt funding the capital program. The company's capacity to borrow for capital projects is sound with a 2020 debt/capital structure of .43, below the lender covenants of 0.6. Forecast borrowings over the 10 year time horizon will maintain the debt/capital structure within lender covenants.

x. ***CAPITAL EXPENDITURES:***

The level of the 2021 sustaining Capital Budget is set at $13.2M (see next page).

The major areas of the capital budget are listed below, for a detailed commentary please refer to the 2021 Business Plan section entitled "BHI Summary".

(000's)	2020 Update	2021 Budget	Change
Sustaining Capital			
- Buildings	$ 318	$ 495	$ 177
- Substation Equip.	490	1,090	600
- Undergound Distribution	2,436	3,575	1,139
- Overhead Distribution	2,467	4,551	2,084
- Transformers	900	900	-
- Meters	617	1,029	412
- Rolling Stock	361	525	164
- Tools	12	39	27
- Computer Hdwe/Sftwe	1,882	488	(1,394)
- Office Equipment	42	5	(37)
	$ 9,525	$ 12,697	$ 3,172
Developer Buybacks	350	450	100
	$ 9,875	$ 13,147	$ 3,272

BURLINGTON HYDRO INC.
10 Year Forecast Assumptions

Financial forecasts are by definition, forward-looking statements. As such, they are subject to risks and uncertainties which may see actual results differ materially from those set forth in these documents.
The statements are based on the beliefs and assumptions of management. The forward-looking statements are not guarantees of performance and the assumptions listed below and elsewhere in this document could affect the future results of operation and could cause the results or outcomes to materially differ from those expressed or implied in the statements due to a number of factors.

These factors include:

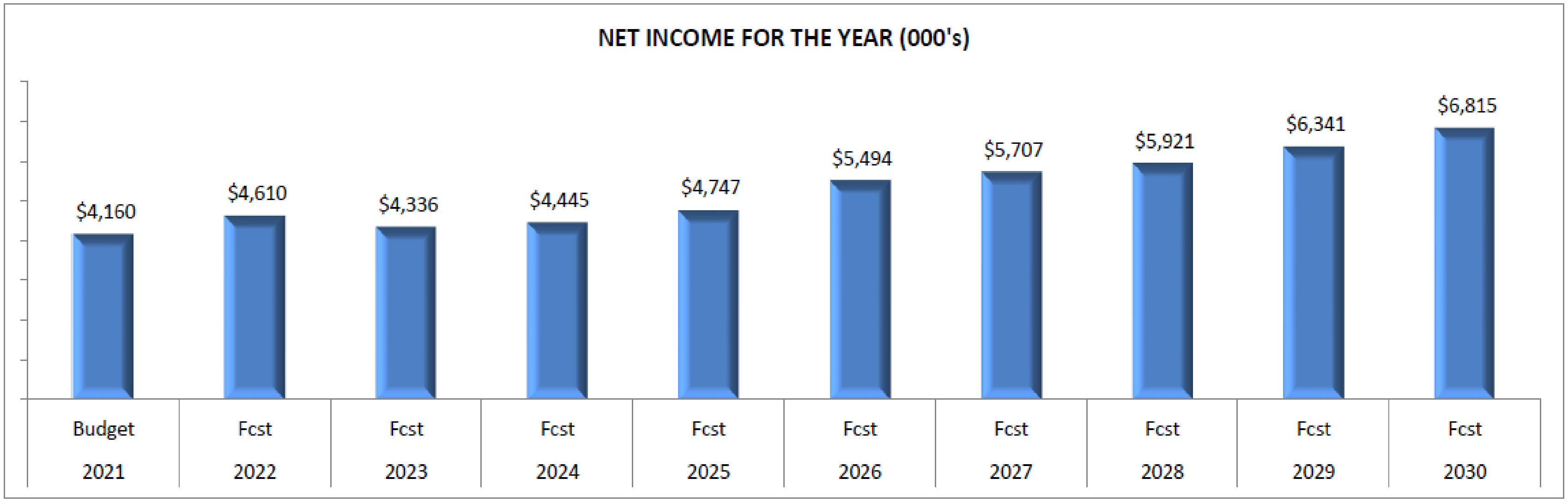
- Government regulations that impact our industry and the way we do business
- Regulatory changes affecting distribution rates
- General economic and business conditions
- Changes in accounting standards and their impact on accounting for regulatory assets
- Weather and its' impact on both the distribution system grid and sales
- Liabilities and other claims.

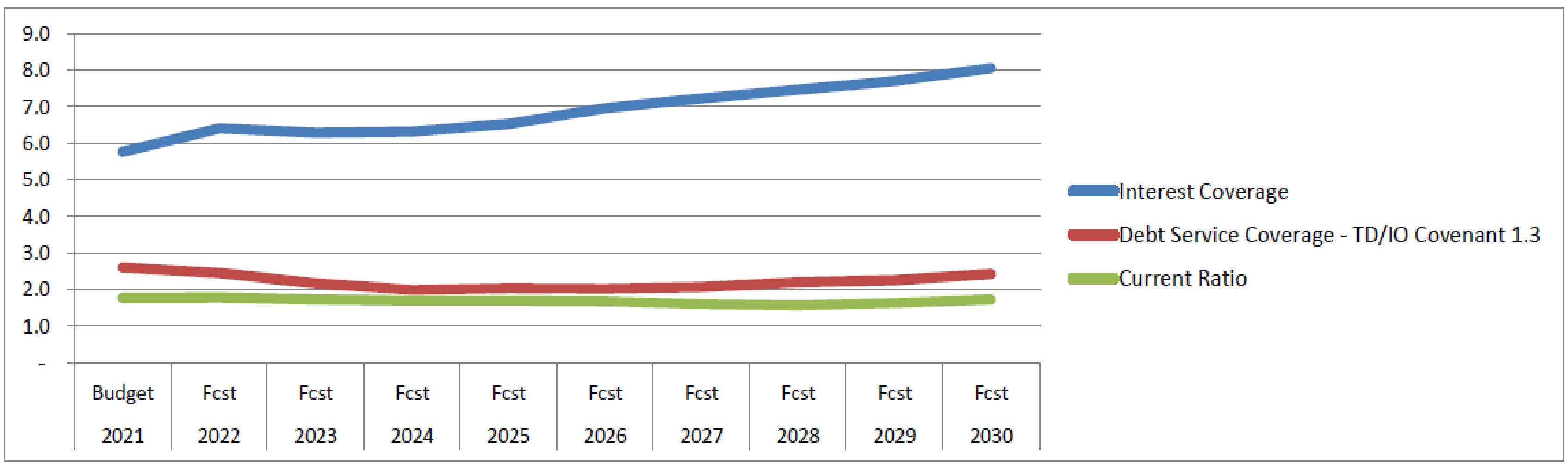
The foregoing list of factors is not intended to be exhaustive.

Dividend forecasts are subject to change based on the working capital needs of the Company, which can be impacted by changes in the cost of electricity.

	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst
Distribution Revenues										
- Distribution Revenue Growth	$ 3,759	$ 638	$ 490	$ 687	$ 889	$ 1,433	$ 945	$ 968	$ 991	$ 1,015
- kWh Change		0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
- OEB Industry Specific Inflation Factor	Rebase	2.20%	2.20%	2.20%	2.20%	Rebase	2.20%	2.20%	2.20%	2.20%
- OEB Stretch Factor	Year	-0.30%	-0.30%	-0.30%	-0.30%	Year	-0.30%	-0.30%	-0.30%	-0.30%
Operating Expenses										
- Inflation Rate		1.65%	2.15%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
- Productivity Factor		0.30%	0.25%	0.20%	0.15%	0.00%	0.30%	0.25%	0.20%	0.15%
Net Change		1.35%	1.90%	2.00%	2.05%	2.20%	1.90%	1.95%	2.00%	2.05%
Cost of Power										
- Escalation Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Prime Rate	2.45%	2.50%	2.50%	2.75%	2.75%	3.00%	3.00%	3.00%	3.00%	3.00%
Investment Rate	0.60%	0.65%	0.65%	0.90%	0.90%	1.15%	1.15%	1.15%	1.15%	1.15%
Rate on City Promissory Note	3.77%	3.21%	3.21%	3.21%	3.21%	3.21%	3.21%	3.21%	3.21%	3.21%
Dividends to BHEI (000's)	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050	$ 2,050

BURLINGTON HYDRO INC.
2021
DASHBOARD





BURLINGTON HYDRO INC. STATEMENT of COMPREHENSIVE INCOME ($000's)	2020 Update	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2020 Bdgt
TOTAL REVENUE	208,933	223,479	227,886	232,218	236,825	241,713	247,225	252,330	257,541	262,860	268,290	213,097
-: Cost of Power Purchased	177,608	188,395	192,163	196,006	199,926	203,925	208,004	212,164	216,407	220,735	225,150	180,824
DISTRIBUTION REVENUE	31,325	35,084	35,723	36,212	36,899	37,788	39,221	40,166	41,134	42,125	43,140	32,273
Other Operating Revenue												
Late Payment Charges	286	299	304	309	314	322	334	342	351	359	368	292
BESI Billiing Service Revenue	401	403	411	423	436	448	460	473	486	498	511	415
Deferred Revenue - amort. of Contr.Capital	743	1,199	1,281	1,349	1,403	1,457	1,509	1,560	1,610	1,659	1,707	852
Miscellaneous	1,987	1,567	1,039	885	889	893	897	901	906	911	916	919
	3,417	3,468	3,035	2,966	3,042	3,120	3,200	3,276	3,353	3,427	3,502	2,479
Operating Expenses												
Operations & Maintenance	9,608	10,755	10,901	11,108	11,330	11,562	11,816	12,041	12,276	12,521	12,778	10,495
Billing & Collection	3,012	3,123	3,165	3,225	3,289	3,357	3,431	3,496	3,564	3,635	3,710	2,904
General Administration	7,964	8,927	8,508	8,669	8,843	9,024	9,222	9,398	9,581	9,773	9,973	7,945
Municipal Tax	336	342	347	353	360	368	376	383	390	398	406	348
Depreciation & Amortization	7,122	8,055	8,199	8,451	8,604	8,749	8,919	9,222	9,513	9,596	9,678	7,216
TOTAL EXPENSES	28,042	31,202	31,119	31,806	32,426	33,060	33,764	34,540	35,324	35,924	36,545	28,908
INCOME FROM OPERATING ACTIVITIES	6,701	7,350	7,639	7,372	7,515	7,848	8,657	8,902	9,163	9,628	10,098	5,843
Interest Expense - short term debt	72	72	72	72	72	72	72	72	72	72	72	72
Interest Expense - long term debt	711	800	862	906	941	934	915	902	892	885	847	711
Interest Expense - Shareholder Note	2,336	1,800	1,537	1,537	1,537	1,537	1,537	1,537	1,537	1,537	1,537	2,336
Interest Expense	3,119	2,672	2,471	2,515	2,550	2,543	2,524	2,510	2,501	2,494	2,456	3,119
Interest Income	130	23	41	43	58	59	75	57	28	30	58	201
Net Finance Costs	2,989	2,649	2,430	2,472	2,492	2,484	2,449	2,454	2,473	2,464	2,397	2,918
INCOME BEFORE INCOME TAXES	3,711	4,701	5,209	4,900	5,023	5,364	6,208	6,449	6,690	7,165	7,700	2,926
Income Taxes	427	541	599	563	578	617	714	742	769	824	886	336
NET INCOME FOR THE YEAR	3,285	4,160	4,610	4,336	4,445	4,747	5,494	5,707	5,921	6,341	6,815	2,589
Other Comprehensive Income (Loss)	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL COMPREHENSIVE INCOME	3,285	4,160	4,610	4,336	4,445	4,747	5,494	5,707	5,921	6,341	6,815	2,589

BURLINGTON HYDRO INC. BALANCE SHEET ($000's)	2020 Update	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst
Current Assets											
Cash	2,182	4,660	5,927	5,306	5,575	5,572	5,511	2,350	531	2,751	5,419
Securities held as Customer Deposits	3,916	4,210	4,287	4,345	4,428	4,535	4,707	4,820	4,936	5,055	5,177
Accounts Receivable	16,600	18,368	18,730	19,086	19,465	19,867	20,320	20,739	21,168	21,605	22,051
Unbilled Revenue	20,035	21,430	21,852	22,268	22,709	23,178	23,707	24,196	24,696	25,206	25,726
Income Taxes Receivable	135	-	-	-	-	-	-	-	-	-	-
Inventory	5,221	5,012	5,103	5,030	5,125	5,106	5,161	5,216	5,274	5,332	5,393
Work Orders in Progress	705	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455	1,455
Prepaid Expenses	525	525	525	525	525	525	525	525	525	525	525
Total Current Assets	49,318	55,660	57,879	58,015	59,282	60,237	61,385	59,302	58,584	61,929	65,746
Net Property Plant & Equipment	168,700	193,848	202,484	209,324	213,779	218,046	222,806	230,385	237,671	240,530	243,322
Deferred Tax Assets	7,737	7,737	7,737	7,737	7,737	7,737	7,737	7,737	7,737	7,737	7,737
TOTAL ASSETS	225,756	257,245	268,100	275,076	280,798	286,020	291,928	297,424	303,992	310,196	316,805
Net Regulatory Asset Balances	8,721	5,600	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
TOTAL ASSETS & Regulatory Balances	234,477	262,845	272,100	279,076	284,798	290,020	295,928	301,424	307,992	314,196	320,805
Current Liabilities											
Current Portion of Long Term Debt	2,151	3,251	4,004	4,783	5,564	5,648	6,164	6,267	6,014	6,047	5,725
Accts Payable & Accrued Liabilities	16,081	17,135	17,422	17,768	18,124	18,487	18,861	19,236	19,620	20,012	20,413
Customer Deposits	3,916	4,210	4,287	4,345	4,428	4,535	4,707	4,820	4,936	5,055	5,177
Work Order Deposits	4,900	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500	4,500
Deferred Revenue - CDM Programs	1,571	105	-	-	-	-	-	-	-	-	-
Other Liabilities	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363	2,363
Total Current Liabilities	30,982	31,564	32,576	33,759	34,978	35,533	36,595	37,186	37,432	37,977	38,178
Deferred Revenue - Cap Contributions	37,755	56,612	61,230	64,448	67,049	69,598	72,094	74,539	76,934	79,280	81,577
Shareholder Note Payable	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879	47,879
Long Term Debt	14,794	21,542	22,538	22,756	22,192	21,544	20,379	19,112	19,099	18,051	17,326
Deferred Tax Liability	10,785	10,785	10,785	10,785	10,785	10,785	10,785	10,785	10,785	10,785	10,785
Liability for Future Benefits	4,565	4,635	4,705	4,775	4,845	4,915	4,985	5,055	5,125	5,195	5,265
TOTAL LIABILITIES	146,759	173,017	179,712	184,401	187,728	190,253	192,717	194,556	197,254	199,167	201,011
Equity											
Capital Stock	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139	45,139
Paid-up Capital	876	876	876	876	876	876	876	876	876	876	876
Retained Earnings	41,885	43,995	46,555	48,841	51,237	53,934	57,378	61,035	64,905	69,196	73,961
Accumulated Other Compr Income	(182)	(182)	(182)	(182)	(182)	(182)	(182)	(182)	(182)	(182)	(182)
TOTAL EQUITY	87,718	89,828	92,388	94,674	97,070	99,767	103,211	106,868	110,738	115,029	119,794
TOTAL LIABILITIES, EQUITY & Reg Balances	234,477	262,845	272,100	279,076	284,798	290,020	295,928	301,424	307,992	314,196	320,805

BURLINGTON HYDRO INC. STATEMENT OF Retained Earnings ($000'S)	2020 Update	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst
Opening Retained Earnings	40,600	41,885	43,995	46,555	48,841	51,237	53,934	57,378	61,035	64,905	69,196
Net Income (loss)	3,285	4,160	4,610	4,336	4,445	4,747	5,494	5,707	5,921	6,341	6,815
Dividends	(2,000)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)
Closing Retained Earnings	41,885	43,995	46,555	48,841	51,237	53,934	57,378	61,035	64,905	69,196	73,961

RATIO ANALYSIS	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Debt/Total Capital - TD Covenant .6	42.5%	44.7%	44.6%	44.3%	43.8%	42.9%	41.9%	40.7%	39.7%	38.5%	37.2%
Debt to Total Assets - IO Covenant .6	28.7%	28.3%	27.8%	27.4%	26.9%	26.2%	25.5%	24.6%	24.0%	23.2%	22.4%
Current Ratio	1.59	1.76	1.78	1.72	1.69	1.70	1.68	1.59	1.57	1.63	1.72
Interest Coverage	4.4	5.8	6.4	6.3	6.3	6.5	7.0	7.2	7.5	7.7	8.1
Debt Service Coverage - TD/IO Covenant 1.3	2.6	2.6	2.4	2.2	2.0	2.0	2.0	2.1	2.2	2.3	2.4

BURLINGTON HYDRO INC. STATEMENT OF CASH FLOWS ($000's)	2020 Update	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst
Operating Activities											
Net Income after Taxes	3,285	4,160	4,610	4,336	4,445	4,747	5,494	5,707	5,921	6,341	6,815
Depreciation	7,122	8,055	8,199	8,451	8,604	8,749	8,919	9,222	9,513	9,596	9,678
Deferred Revenue Amortization	(743)	(1,199)	(1,281)	(1,349)	(1,403)	(1,457)	(1,509)	(1,560)	(1,610)	(1,659)	(1,707)
	9,663	11,017	11,528	11,439	11,646	12,040	12,904	13,369	13,824	14,278	14,785
Non-Cash Working Capital Changes											
Change in A/R	(701)	(1,768)	(362)	(356)	(379)	(402)	(453)	(420)	(428)	(437)	(446)
Change in Unbilled Revenue	3,509	(1,395)	(423)	(415)	(442)	(469)	(529)	(490)	(500)	(510)	(521)
Change in Income Tax Receivable	30	135	-	-	-	-	-	-	-	-	-
Change in Inventory	95	209	(91)	74	(95)	18	(54)	(56)	(57)	(59)	(60)
Change in WIP	647	(750)	-	-	-	-	-	-	-	-	-
Change in A/P & Accrued Liabilities	(2,178)	1,054	287	347	355	363	374	375	384	392	401
Change in W/O Deposits	364	(400)	-	-	-	-	-	-	-	-	-
Change in Deferred Revenue	58	(1,466)	(105)	-	-	-	-	-	-	-	-
Change in Liability for Future Benefits	75	70	70	70	70	70	70	70	70	70	70
Change in Regulatory Balances	(985)	3,121	1,600	-	-	-	-	-	-	-	-
	914	(1,190)	976	(281)	(490)	(419)	(592)	(520)	(531)	(544)	(556)
Operating Cash Flow	10,577	9,827	12,504	11,157	11,156	11,621	12,312	12,850	13,292	13,734	14,229
Investing Activities											
Net Additions to PP&E	9,875	13,147	10,936	10,724	9,054	9,011	9,674	12,796	12,794	8,451	8,464
Additions to PP&E (from CC)	15,193	20,056	5,899	4,567	4,005	4,005	4,005	4,005	4,005	4,005	4,005
Net Cash Used for Investing Activities	25,068	33,203	16,835	15,291	13,059	13,016	13,679	16,801	16,799	12,456	12,469
Financing Activities											
Change in Securities Held as Customer Deposits	(18)	(294)	(77)	(59)	(82)	(107)	(172)	(113)	(116)	(119)	(122)
Change in Customer Deposits	18	294	77	59	82	107	172	113	116	119	122
Change in Current Portion of L-T Debt	710	1,100	753	778	781	85	516	103	(253)	34	(322)
Change in L-T Debt	(2,176)	6,749	996	217	(564)	(648)	(1,164)	(1,267)	(14)	(1,047)	(725)
Deferred Revenue	15,193	20,056	5,899	4,567	4,005	4,005	4,005	4,005	4,005	4,005	4,005
Net Cash Provided by Financing Activities	13,727	27,904	7,648	5,563	4,222	3,441	3,357	2,841	3,738	2,991	2,958
Increase (decrease) in Cash & Cash Equivalents	(764)	4,528	3,317	1,429	2,319	2,046	1,990	(1,111)	231	4,270	4,718
Cash & Cash Equivalents, Beginning of Year	4,946	2,182	4,660	5,927	5,306	5,575	5,572	5,511	2,350	531	2,751
Dividends Paid to BHEI	(2,000)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)	(2,050)
Cash & Cash Equivalents, End of Year	2,182	4,660	5,927	5,306	5,575	5,572	5,511	2,350	531	2,751	5,419

BURLINGTON HYDRO INC. CAPITAL BUDGET ($000's)	2020 Update	2021 Budget	2022 Fcst	2023 Fcst	2024 Fcst	2025 Fcst	2026 Fcst	2027 Fcst	2028 Fcst	2029 Fcst	2030 Fcst	2020 Bdgt
SUSTAINING CAPITAL BUDGET												
Buildings	318	495	125	45	45	45	45	45	45	45	45	420
Substation Equipment	490	1,090	1,295	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020	670
Projects - 4.16 , 15 & 27.6KV, TS	4,903	8,126	5,587	5,638	4,650	4,700	4,650	4,700	4,650	4,700	4,650	5,760
Transformers	900	900	900	900	900	900	900	900	900	900	900	900
Meters	617	1,029	864	864	864	864	964	5,184	5,184	864	864	873
Rolling Stock	361	525	245	395	705	620	726	60	125	60	115	364
Tools	12	39	12	12	12	12	12	12	12	12	12	12
Computer Hardware/Software	1,882	488	1,370	1,380	380	380	880	380	380	380	380	858
Office Equipment	42	5	88	20	28	20	27	45	28	20	28	58
	9,525	12,697	10,486	10,274	8,604	8,561	9,224	12,346	12,344	8,001	8,014	9,915
Developer Asset BuyBacks	350	450	450	450	450	450	450	450	450	450	450	350
SUSTAINING CAPITAL BUDGET	9,875	13,147	10,936	10,724	9,054	9,011	9,674	12,796	12,794	8,451	8,464	10,265
CAPITAL CONTRIBUTIONS												
General Service Projects	13,193	18,056	3,899	2,567	2,005	2,005	2,005	2,005	2,005	2,005	2,005	8,779
Developer Assets Assumed	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
CAPITAL CONTRIBUTIONS	15,193	20,056	5,899	4,567	4,005	4,005	4,005	4,005	4,005	4,005	4,005	10,779
TOTAL CAPITAL BUDGET	25,068	33,203	16,835	15,291	13,059	13,016	13,679	16,801	16,799	12,456	12,469	21,044

Appendix C – Certification of Evidence

Burlington**hydro** inc.

CERTIFICATION OF THE EVIDENCE

EB-2020-0007

I, Gerry Smallegange, President and Chief Executive Officer of Burlington Hydro Inc. hereby certify that, to the best of my knowledge, the evidence filed in support of BHI's 2021 Cost of Service Application is accurate, consistent and complete.

This certification is provided pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications - 2020 Edition for 2021 Rate Applications - Chapter 2 Cost of Service* as issued on May 14, 2020.

DATED this **30th** day of **October, 2020.**

Gerry Smallegange
President and Chief Executive Officer
Burlington Hydro Inc.

Appendix D – BHI OEB Scorecard

Scorecard - Burlington Hydro Inc.

9/11/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		98.30%	96.70%	97.72%	98.31%	100.00%		90.00%	
		Scheduled Appointments Met On Time		99.60%	100.00%	100.00%	99.81%	100.00%		90.00%	
		Telephone Calls Answered On Time		75.60%	74.70%	80.13%	83.28%	81.43%		65.00%	
	Customer Satisfaction	First Contact Resolution		94%	92	96	91	82.4%			
		Billing Accuracy		99.95%	99.97%	99.96%	99.76%	99.97%		98.00%	
		Customer Satisfaction Survey Results		90%	86	92	94	96%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		81.00%	81.00%	84.00%	84.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.18	0.98	1.04	1.44	1.05			1.09
		Average Number of Times that Power to a Customer is Interrupted [2]		0.71	0.60	0.64	0.85	0.75			1.07
	Asset Management	Distribution System Plan Implementation Progress		On Track	OnTrack	On Track	On Track	n/a			
	Cost Control	Efficiency Assessment		3	2	2	2	2			
		Total Cost per Customer [3]		$616	$620	$608	$627	$661			
		Total Cost per Km of Line [3]		$26,730	$27,518	$26,606	$27,766	$29,293			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		12.75%	26.39%	62.56%	81.00%	96.00%			99.04 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	97.87%	97.37%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		2.46	2.51	2.25	2.52	2.07			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.81	0.78	0.75	0.80	0.75			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%			
			Achieved	9.20%	7.98%	6.69%	6.43%	7.16%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the 2015-2020 Conservation First Framework. 2018 results are based on the IESO's unverified savings values contained in the March 2019 Participation and Cost Report.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

Appendix E – 2018 Non-Consolidated Audited Financial Statements

Financial Statements of

BURLINGTON HYDRO INC.

Year ended December 31, 2018

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
Canada
Telephone (905) 523-8200
Fax (905) 523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Burlington Hydro Inc.

Opinion

We have audited the financial statements of Burlington Hydro Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2018
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the statement of financial position of the Entity as at December 31, 2018, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
March 18, 2019

BURLINGTON HYDRO INC.

Statement of Financial Position

Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Assets			
Current assets			
Cash		$ 13,967,146	$ 13,100,175
Securities held as customer deposits	6	3,835,064	3,623,166
Accounts receivable	7	18,694,434	20,004,030
Unbilled revenue		19,941,776	18,803,697
Income taxes receivable		265,320	1,396,497
Material and supplies	8	4,566,351	3,450,124
Prepaid expenses		511,754	446,876
Total current assets		61,781,845	60,824,565
Non-current assets			
Property, plant and equipment	9	129,612,763	122,979,809
Intangible assets	10	7,067,112	6,486,556
Deferred tax assets	11	6,078,843	5,467,356
		142,758,718	134,933,721
Total assets		204,540,563	195,758,286
Regulatory balances	12	21,503,996	27,673,073
Total assets and regulatory balances		$ 226,044,559	$ 223,431,359

BURLINGTON HYDRO INC.

Statement of Financial Position

Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	13	$ 14,621,422	$ 17,828,872
Current portion of long-term debt	14	1,527,283	1,015,237
Customer deposits	6	3,835,064	3,623,166
Work order deposits		4,985,112	3,554,415
Deferred revenue		1,714,235	865,218
Other liabilities		3,755,831	4,135,690
Total current liabilities		30,438,947	31,022,598
Non-current liabilities			
Deferred revenue	15	17,568,377	14,792,210
Deferred tax liabilities	11	8,010,729	5,896,221
Long-term debt	14	66,091,183	60,618,466
Liability for future benefits	16	4,870,343	5,156,792
Total non-current liabilities		96,540,632	86,463,689
Total liabilities		126,979,579	117,486,287
Equity			
Share capital	17	45,139,138	45,139,138
Paid-up capital		876,228	876,228
Retained earnings		37,845,969	35,681,342
Accumulated other comprehensive loss		(546,624)	(796,193)
Total equity		83,314,711	80,900,515
Total liabilities and equity		210,294,290	198,386,802
Regulatory balances	12	15,750,269	25,044,557
Total liabilities, equity and regulatory balances		$ 226,044,559	$ 223,431,359

See accompanying notes to the financial statements.

On behalf of the Board:

____________________________ Director   ____________________________ Director

BURLINGTON HYDRO INC.

Statement of Comprehensive Income

Year ended December 31, 2018, with comparative information for 2017

	Note	2018	2017
Revenue			
Distribution revenue		$ 30,706,157	$ 29,953,460
Other operating revenue		3,093,155	2,185,795
		33,799,312	32,139,255
Sale of electricity		187,840,861	193,469,626
Total revenue	18	221,640,173	225,608,881
Operating expenses			
Operations and maintenance		9,772,267	9,075,288
Billing and customer service		3,108,174	2,769,029
General administration		7,395,573	7,443,991
Depreciation and amortization		5,927,266	5,562,586
	19	26,203,280	24,850,894
Cost of power purchased		189,166,371	197,091,122
Total expenses		215,369,651	221,942,016
Income from operating activities		6,270,522	3,666,865
Net finance costs	20	(2,757,307)	(2,890,703)
Income before income taxes		3,513,215	776,162
Income taxes			
Current	11	310,758	(472,817)
Future	11	1,413,041	1,709,566
		1,723,799	1,236,749
Net income (loss) after income taxes		1,789,416	(460,587)
Net movement in regulatory balances, net of tax			
Net movement in regulatory balances		2,345,628	3,971,606
Income tax on net movement in regulatory balances		779,583	724,177
		3,125,211	4,695,783
Net income and net movement in regulatory balances		4,914,627	4,235,196
Other comprehensive income (loss)			
Remeasurements of liability for future benefits, net of tax		249,569	(211,664)
Total comprehensive income		$ 5,164,196	$ 4,023,532

See accompanying notes to the financial statements.

BURLINGTON HYDRO INC.

Statement of Changes in Equity

Year ended December 31, 2018, with comparative information for 2017

	Share capital	Contributed surplus	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2017	$ 45,139,138	$ 876,228	$ 33,446,146	$ (584,529)	$ 78,876,983
Net income and net movement in regulatory balances	-	-	4,235,196	-	4,235,196
Other comprehensive loss	-	-	-	(211,664)	(211,664)
Dividends	-	-	(2,000,000)	-	(2,000,000)
Balance at December 31, 2017	$ 45,139,138	$ 876,228	$ 35,681,342	$ (796,193)	$ 80,900,515
Balance at January 1, 2018	$ 45,139,138	$ 876,228	$ 35,681,342	$ (796,193)	$ 80,900,515
Net income and net movement in regulatory balances	-	-	4,914,627	-	4,914,627
Other comprehensive income	-	-	-	249,569	249,569
Dividends	-	-	(2,750,000)	-	(2,750,000)
Balance at December 31, 2018	$ 45,139,138	$ 876,228	$ 37,845,969	$ (546,624)	$ 83,314,711

See accompanying notes to the financial statements.

BURLINGTON HYDRO INC.

Statement of Cash Flows

Year ended December 31, 2018, with comparative information for 2017

	2018	2017
Operating activities		
Net income and net movement in regulatory balances	$ 4,914,627	$ 4,235,196
Adjustments for:		
Depreciation and amortization	5,927,266	5,562,586
Amortization of deferred revenue	(375,497)	(289,167)
Post-employment benefits	53,101	91,715
Losses on disposal of property, plant and equipment	296,159	12,219
Net finance costs	2,658,589	2,818,214
Income tax expense	1,723,799	1,236,749
Contributions received from customers	3,151,664	4,681,623
Change in non-cash operating working capital:		
Accounts receivable	1,309,596	5,485,991
Unbilled revenue	(1,138,079)	8,992,493
Materials and supplies	(1,116,227)	(691,523)
Prepaid expenses	(64,878)	(8,637)
Accounts payable and accrued liabilities	(3,207,450)	(993,971)
Work order deposits	1,430,697	816,901
Deferred revenue	849,017	(46,653)
Other liabilities	(379,859)	1,989,120
	16,032,525	33,892,856
Regulatory balances	(3,125,211)	(4,695,783)
Income tax paid	(479,710)	(1,693,397)
Income tax received	1,300,129	1,036,090
Interest paid	(2,985,949)	(3,020,015)
Interest received	327,359	201,801
Net cash from operating activities	11,069,143	25,721,552
Investing activities		
Purchase of property, plant and equipment	(12,224,179)	(13,007,784)
Proceeds on disposal of property, plant and equipment	46,258	31,202
Purchase of intangible assets	(1,259,014)	(256,367)
Net cash used by investing activities	(13,436,935)	(13,232,949)
Financing activities		
Dividends paid	(2,750,000)	(2,000,000)
Proceeds from long-term debt	7,000,000	-
Repayment of long-term debt	(1,015,237)	(971,606)
Net cash used in financing activities	3,234,763	(2,971,606)
Change in cash	866,971	9,516,997
Cash, beginning of year	13,100,175	3,583,178
Cash, end of year	$ 13,967,146	$ 13,100,175

See accompanying notes to the financial statements.

1. Reporting entity

Burlington Hydro Inc. is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the City of Burlington (“City”). The address of the Corporation’s registered office is 1340 Brant Street, Burlington, Ontario, L7R 3Z7.

The Corporation delivers electricity and related energy services to residential and commercial customers in the City of Burlington. The Corporation is wholly owned by Burlington Hydro Electric Inc. and the ultimate parent company is the City.

The financial statements are for the Corporation as at and for the year ended December 31, 2018.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on March 18, 2019.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Rate regulation

The Corporation is regulated by the Ontario Energy Board (“OEB”), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

2. Basis of presentation (continued)

(d) Rate regulation (continued)

Rate setting

Distribution revenue

For distribution revenue, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners, and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“OEB Inflation”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application on October 2, 2013 for rates effective May 1, 2014 to April 30, 2015. In 2018, the Corporation had a cohort ranking with the OEB as Group 2 which is a stretch factor of 0.15%. This resulted in a net adjustment to rates on May 1, 2018 of 1.05% (2017 - 1.60%) comprised of the OEB Inflation for 2018 of 1.20% (2017 - 1.90%), the Corporation's productivity factor of 0.0% (2017 - 0.0%), and the stretch factor of 0.15% (2017 - 0.30%).

The OEB issued a new distribution rate design for residential electricity customers which is being phased in over a four year period commencing January 2016. Under this new policy, electricity distributors will structure residential rates so that all distribution charges will be collected through a full fixed monthly charge instead of the current fixed and variable rate charge.

Effective in 2017, all electricity distributors in Ontario are required to bill their customers on a monthly basis rather than the current bi-monthly basis. This policy change incorporates an expectation that distributors will issue bills based on actual meter readings rather than estimates, at least 98% of the time.

2. Basis of presentation (continued)

(d) Rate regulation (continued)

Electricity rates - Commodity

The OEB sets electricity prices for certain low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity or pursuant to their contract with a retailer. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

(e) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Notes 3(d) and (e) – estimation of useful lives of its property, plant and equipment and intangible assets
(ii) Note 3(i) – recognition and measurement of regulatory balances
(iii) Note 16 – measurement of defined benefit obligations: key actuarial assumptions
(iv) Note 21 – recognition and measurement of provisions and contingencies

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

(i) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period
(ii) Note 22 – leases: whether an arrangement contains a lease

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment of the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other operating revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance are presented as deferred revenue.

Government grants and the related performance incentive payments under CDM (“Conservation and Demand Management”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Significant accounting policies (continued)

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Years
Buildings	10 - 50
Sub-station buildings	50
Sub-station equipment	20 - 40
Distribution lines – overhead	20 - 60
Distribution lines – underground	30 - 60
Distribution – transformers	40
Distribution – meters	15 - 45
Rolling stock	8 - 20
Tools and equipment	10 - 15
Office equipment	10
Computer equipment	5

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated amortization. All intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Asset	Years
Computer software	5
Land rights	35 - 70
Transformer station right	60

3. Significant accounting policies (continued)

(f) Impairment

(i) Financial assets measured at amortized cost

A loss provision for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss provision is measured at an amount equal to the lifetime expected credit losses for the asset. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the impairment requirements is no longer met.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies, and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Significant accounting policies (continued)

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Regulatory balances

Regulatory debit balances represent costs incurred in excess of amounts billed to the customer. Regulatory credit balances represent amounts billed to the customer in excess of costs incurred by the Corporation.

Regulatory debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or Other Comprehensive Income ("OCI"). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory debit balances is assessed annually based upon the likelihood that the OEB will approve rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized as a loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities.

3. Significant accounting policies (continued)

(j) Post-employment benefits (continued)

(i) Pension plan (continued)

The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Leased assets

Leases, where the terms cause the Corporation to assume substantially all the risks and rewards of ownership, are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

All other leases are classified as operating leases and the leased assets are not recognized on the Corporation's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash balances.

Finance costs comprise interest expense on borrowings and are recognized in profit or loss.

3. Significant accounting policies (continued)

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Change in accounting policy

IFRS 15 Revenue from Contracts with Customers and IFRS 9 Financial Instruments

The Corporation has initially applied IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* from January 1, 2018 on a retrospective basis. The following practical expedients have been used in the initial application of these new standards:

For completed contracts, the Corporation did not restate contracts that:

(i) Began and ended within the same annual reporting period; or

(ii) Were completed at the beginning of January 1, 2016.

There have been no material changes to the Corporation's comparative figures as a result of this implementation.

5. Future changes in accounting policy and disclosures

The Corporation is still evaluating the following new and revised standards along with any subsequent amendments.

Leases

In January 2016, IASB issued IFRS 16 to establish principles for the recognition, measurement, presentation, and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. IFRS 16 replaces IAS 17 and it is effective for annual periods beginning on or after January 1, 2019. The standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. This standard substantially carries forward the lessor accounting requirements of IAS 17, while requiring enhanced disclosures to be provided by the lessor.

Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning January 1, 2019. The Corporation does not expect the standard to have a material impact on the financial statements.

6. Securities held as customers deposits

The OEB requires companies to periodically review customers' deposits and where appropriate, refund such deposits. During this review, companies may also request a deposit from customers based on certain criteria.

The Corporation has a policy of funding customers' deposits and paying interest on these deposits at a rate determined quarterly. Securities held as customers' deposits represent the funds segregated to fund the customer deposit refunds. The average rate of interest paid by the Corporation for 2018 was 1.70% (2017 – 0.95%).

7. Accounts receivable

	2018	2017
Customer trade receivables	$ 15,458,130	$ 15,801,564
Receivables from the City	581,454	693,615
Receivables from other related parties	9,312	7,092
Work in progress	1,126,291	588,549
Other	1,749,247	3,113,210
	18,924,434	20,204,030
Less: Provision for expected credit losses	230,000	200,000
	$ 18,694,434	$ 20,004,030

8. Materials and supplies

The amount written down due to obsolescence in 2018 was $14,580 (2017 – $60,538).

9. Property, plant and equipment

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Land	$ 299,003	$ -	$ -	$ -	$ 299,003
Buildings	5,156,213	452,831	-	-	5,609,044
Sub-station buildings	1,249,684	7,733	-	-	1,257,417
Sub-station equipment	6,003,427	297,022	-	-	6,300,449
Distribution lines – overhead	45,444,828	4,227,972	-	19,197	49,653,603
Distribution lines – underground	39,841,821	4,272,078	-	232	44,113,667
Distribution – transformers	25,815,845	1,444,132	-	88,445	27,171,532
Distribution – meters	13,221,734	611,728	-	649,928	13,183,534
Rolling stock	2,351,972	571,509	-	437,493	2,485,988
Tools and equipment	310,937	10,099	-	-	321,036
Office equipment	646,377	60,230	-	6,161	700,446
Computer equipment	403,691	268,845	-	-	672,536
	140,745,532	12,224,179	-	1,201,456	151,768,255
Accumulated Depreciation					
Buildings	1,038,574	276,471	-	-	1,315,045
Sub-station buildings	257,951	66,559	-	-	324,510
Sub-station equipment	1,300,066	319,374	-	-	1,619,440
Distribution lines – overhead	4,418,797	1,306,756	-	8,262	5,717,291
Distribution lines – underground	3,201,279	1,060,262	-	93	4,261,448
Distribution – transformers	2,616,118	821,581	-	55,036	3,382,663
Distribution – meters	3,761,997	1,005,910	-	358,427	4,409,480
Rolling stock	528,099	211,449	-	431,058	308,490
Tools and equipment	150,904	32,342	-	-	183,246
Office equipment	205,352	71,459	-	6,161	270,650
Computer equipment	286,586	76,643	-	-	363,229
	17,765,723	5,248,806	-	859,037	22,155,492
Carrying amount	$ 122,979,809	$ 6,975,373	$ -	$ 342,419	$129,612,763

9. Property, plant and equipment (continued)

	January 1, 2017	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2017
Cost					
Land	$ 299,003	$ -	$ -	$ -	$ 299,003
Buildings	5,125,057	31,156	-	-	5,156,213
Sub-station buildings	1,199,994	49,690	-	-	1,249,684
Sub-station equipment	5,893,552	109,875	-	-	6,003,427
Distribution lines – overhead	42,809,866	2,646,063	-	11,101	45,444,828
Distribution lines – underground	33,016,276	6,825,545	-	-	39,841,821
Distribution – transformers	23,893,616	1,992,455	-	70,226	25,815,845
Distribution – meters	12,624,879	596,855	-	-	13,221,734
Rolling stock	1,965,545	462,293	-	75,866	2,351,972
Tools and equipment	297,117	13,820	-	-	310,937
Office equipment	415,617	256,069	-	25,309	646,377
Computer equipment	381,429	23,963	-	1,701	403,691
	127,921,951	13,007,784	-	184,203	140,745,532
Accumulated Depreciation					
Buildings	771,342	267,232	-	-	1,038,574
Sub-station buildings	191,480	66,471	-	-	257,951
Sub-station equipment	986,405	313,661	-	-	1,300,066
Distribution lines – overhead	3,198,143	1,227,248	-	6,594	4,418,797
Distribution lines – underground	2,254,893	946,386	-	-	3,201,279
Distribution – transformers	1,890,212	778,513	-	52,607	2,616,118
Distribution – meters	2,788,206	973,791	-	-	3,761,997
Rolling stock	402,756	180,226	-	54,883	528,099
Tools and equipment	113,611	37,293	-	-	150,904
Office equipment	167,881	62,780	-	25,309	205,352
Computer equipment	218,812	69,163	-	1,389	286,586
	12,983,741	4,922,764	-	140,782	17,765,723
Carrying amount	$ 114,938,210	$ 8,085,020	$ -	$ 43,421	$ 122,979,809

The Corporation leases equipment under a number of finance lease agreements. The leased equipment secures lease obligations (see note 14). At December 31, 2018 the net carrying amount of leased equipment was $270,356 (2017 – $409,208).

No interest was capitalized to property, plant and equipment during the year.

Assets with a carrying amount of $129,612,763 (2017 – $122,979,809) are subject to a general security agreement.

10. Intangible assets

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Land rights	$ 160,008	$ -	$ -	$ -	$ 160,008
Computer software	4,432,711	259,014	-	-	4,691,725
Transformer station right	4,079,322	1,000,000	-	-	5,079,322
	8,672,041	1,259,014	-	-	9,931,055
Accumulated Depreciation					
Land rights	11,312	2,520	-	-	13,832
Computer software	1,899,933	599,044	-	-	2,498,977
Transformer station right	274,240	76,894	-	-	351,134
	2,185,485	678,458	-	-	2,863,943
Carrying amount	$ 6,486,556	$ 580,556	$ -	$ -	$ 7,067,112

	January 1, 2017	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2017
Cost					
Land rights	$ 160,008	$ -	$ -	$ -	$ 160,008
Computer software	4,315,470	256,367	(139,126)	-	4,432,711
Transformer station right	4,079,322	-	-	-	4,079,322
	8,554,800	256,367	(139,126)	-	8,672,041
Accumulated Depreciation					
Land rights	8,484	2,828	-	-	11,312
Computer software	1,331,499	568,434	-	-	1,899,933
Transformer station right	205,680	68,560	-	-	274,240
	1,545,663	639,822	-	-	2,185,485
Carrying amount	$ 7,009,137	$ (383,455)	$(139,126)	$ -	$ 6,486,556

During the year, $nil (2017 – $139,126) computer software was transferred to regulatory debit balances.

11. Income tax expense

Current tax expense

	2018	2017
Current period	$ 294,319	$ (419,173)
Prior period adjustments	16,439	(53,644)
	$ 310,758	$ (472,817)

11. Income tax expense (continued)

Deferred tax expense

	2018	2017
Origination and reversal of temporary differences	$ 1,413,041	$ 1,709,566
Tax adjustment included in other comprehensive income	89,980	(76,315)
	$ 1,503,021	$ 1,633,251

Reconciliation of effective tax rate

	2018	2017
Income before taxes	$ 3,513,215	$ 776,162
Canada and Ontario statutory income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	931,002	205,683
Increase (decrease) in income taxes resulting from:		
Permanent differences	6,456	10,943
Under provided in prior periods	139,922	4,052
Regulatory	621,591	1,052,475
Other adjustments	24,828	(36,404)
Income tax expense	$ 1,723,799	$ 1,236,749

Significant components of the Corporation's deferred tax balances

	2018	2017
Deferred tax (liabilities) assets:		
Property, plant and equipment	$ (6,852,066)	$ (5,472,614)
Intangible assets	(232,148)	(200,916)
Post-employment benefits	1,290,641	1,419,550
Regulatory deferral account balances	(926,515)	(222,691)
Deferred revenue	4,655,620	3,919,936
Other	132,582	127,870
	$ (1,931,886)	$ (428,865)

12. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Group 1 deferral accounts	$ 4,354,710	$171,118,267	$ (171,331,003)	$ 4,141,974	2
Stranded meter cost	59,743	-	(59,743)	-	-
Regulatory settlement account	20,428,907	10,923	(7,638,263)	12,801,567	1
Other regulatory accounts	1,180,701	985,151	(33,992)	2,131,860	3
Income tax	1,649,012	779,583	-	2,428,595	-
	$ 27,673,073	$172,893,924	$ (179,063,001)	$ 21,503,996	

Regulatory deferral account debit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining recovery/ reversal years
Group 1 deferral accounts	$ 3,514,897	$ 79,095,508	$ (78,255,695)	$ 4,354,710	2
Stranded meter costs	59,694	49	-	59,743	1
Regulatory settlement account	14,420,028	43,812	5,965,067	20,428,907	1
Other regulatory accounts	644,709	559,097	(23,105)	1,180,701	3
Income tax	924,835	724,177	-	1,649,012	-
	$ 19,564,163	$ 80,422,643	$ (72,313,733)	$ 27,673,073	

Regulatory deferral account credit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining years
Group 1 deferral accounts	$ (3,622,269)	$ 18,112,078	$ (16,451,708)	$ (1,961,899)	2
Regulatory settlement account	(21,322,439)	(39,657)	7,599,848	(13,762,248)	1
Other regulatory accounts	(99,849)	(274)	74,001	(26,122)	3
Income tax	-	-	-	-	-
	$ (25,044,557)	$ 18,072,147	$ (8,777,859)	$ (15,750,269)	

Regulatory deferral account credit balances	January 1, 2017	Additions	Recovery/ reversal	December 31, 2017	Remaining years
Group 1 deferral accounts	$ (8,092,824)	$117,974,429	$ (113,503,874)	$ (3,622,269)	2
Regulatory settlement account	(13,578,838)	(91,581)	(7,652,020)	(21,322,439)	1
Other regulatory accounts	(98,894)	(955)	-	(99,849)	3
Income tax	-	-	-	-	-
	$ (21,770,556)	$117,881,893	$ (121,155,894)	$ (25,044,557)	

12. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using historical data. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

The Corporation seeks authorization to settle the Group 1 deferral accounts through application to the OEB as part of the annual rate application. Settlement is typically done through volumetric rate riders. Since future consumption volumes are impacted by exogenous factors (e.g. weather, economic conditions) the amount actually disposed of through the operation of the authorized rate rider varies from the balance authorized for disposition. The OEB authorized the Corporation to dispose of $(2,726,558) through rate riders which expired on April 30, 2018. The OEB authorized the Corporation to dispose of $(2,157,475) through rate riders that took effect May 1, 2018 and will expire on April 30, 2019. An application has been made to the OEB to dispose of $3,021,456 of Group 1 deferral account balances; approval for which is pending. Once approval is received, the approved account balance will be moved to the regulatory settlement account.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2018, the average rate was 1.86% (2017 – 1.20%).

13. Accounts payable and accrued liabilities

	2018	2017
IESO – energy purchases	$ 6,426,918	$ 8,162,492
Regional Municipality of Halton	4,713,530	4,594,274
Trade payables	3,421,742	4,979,547
Payable to related parties	59,232	92,559
	$ 14,621,422	$ 17,828,872

14. Long-term debt

	2018	2017
Notes payable	$ 47,878,608	$ 47,878,608
Ontario Infrastructure loan and note	19,469,502	13,345,887
Finance lease liabilities	270,356	409,208
	67,618,466	61,633,703
Current portion	1,527,283	1,015,237
Long-term portion	$ 66,091,183	$ 60,618,466

The notes payable bear interest at 4.88% are unsecured and are due on demand to the City. The City has waived its right to demand payment until January 1, 2020.

The Corporation obtained an Ontario Infrastructure Projects Corporation (“OIPC”) Fixed Term Loan of $10,000,000 on March 15, 2011 due March 15, 2026. The loan bears interest at a rate of 4.51%. The loan is payable in the amount of $76,550 monthly principal and interest.

On March 8, 2013, the Corporation obtained a loan from the OIPC in the form of a Promissory Note of $8,000,000 due March 1, 2038. The Note bears interest at a rate of 4.02%. The Note is payable in the amount of $42,315 monthly principal and interest.

On December 17, 2018, the Corporation obtained a loan from the OIPC in the form of a Promissory Note of $7,000,000 due December 17, 2033. The note bears interest at a rate of 3.63%. The note is payable in the amount of $50,490 monthly principal and interest.

The OIPC facilities are secured by a general security agreement over the assets of the Corporation.

Scheduled repayments of long term debt, excluding finance lease amounts, for the years ended December 31 are as follows:

2019	$ 1,273,258
2020	1,327,400
2021	1,383,864
2022	1,442,751
2023	1,504,166
Thereafter	60,416,668
	$ 67,348,107

14. Long-term debt (continued)

Finance lease liabilities are due as follows:

	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments				
December 31, 2018	$ 259,926	$ 17,417	$ -	$ 277,343
December 31, 2017	156,757	277,343	-	434,100
Interest				
December 31, 2018	6,419	55	-	6,474
December 31, 2017	16,591	6,474	-	23,065
Present value of minimum lease payments				
December 31, 2018	257,375	17,293	-	274,668
December 31, 2017	154,223	274,283	-	428,506

15. Deferred revenue

Deferred revenue relates to the capital contributions received from customers and others. The amount of deferred revenue received from customers and others is $17,568,377 (2017 – $14,792,210). Deferred revenue is recognized as revenue on a straight-line basis over the life of asset for which the contribution was received.

16. Liability for future benefits

(a) OMERS pension plan

As at December 31, 2018, the OMERS plan was 96.0% funded (2017 – 94.0%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. In 2018, the Corporation made employer contributions of $1,028,087 to OMERS (2017 – $1,002,696), of which $174,944 (2017 – $201,777) has been capitalized as part of PP&E and the remaining amount of $853,143 (2017 – $800,919) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,108,776 to OMERS will be made in 2019.

16. Liability for future benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2018	2017
Defined benefit obligation, beginning of year	$ 5,156,792	$ 4,777,098
Included in profit or loss		
Current service cost	191,340	183,526
Interest cost	165,168	176,433
	5,513,300	5,137,057
Included in OCI		
Actuarial losses (gains) arising from:		
Changes in financial assumptions	(339,550)	287,979
	(339,550)	287,979
Benefits paid	(303,407)	(268,244)
Defined benefit obligation, end of year	$ 4,870,343	$ 5,156,792

Actuarial assumptions	2018	2017
General inflation	2.00%	2.00%
Discount (interest) rate	3.90%	3.30%
Salary levels	2.10%	2.10%
Medical costs	3.78%	3.99%
Dental costs	2.50%	2.50%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $500,000. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $620,000.

17. Share capital

	2018	2017
Authorized:		
Unlimited number of common shares		
Issued:		
2,000 common shares	$ 45,139,138	$ 45,139,138

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid dividends in the year on common shares of $1,375 per share (2017 – $1,000) which amount to total dividends paid in the year of $2,750,000 (2017 – $2,000,000).

18. Revenue

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. Other sources of revenue include performance incentive payments under CDM programs.

	2018	2017
Revenue from contracts with customers	$ 218,547,018	$ 223,423,086
Other revenue		
Government grants under CDM programs – OPA	908,308	4,677
Collection charges	462,783	447,212
Regional Municipality of Halton billing contract	399,321	395,685
Amortization of deferred revenue	375,497	289,167
Pole rental	329,783	329,782
Late payment charges	304,816	271,656
Change of occupancy	192,435	207,236
Other	416,371	252,599
Loss on disposal of property, plant and equipment	(296,159)	(12,219)
Total revenue	$ 221,640,173	$ 225,608,881

18. Revenue (continued)

In the following table, revenue from contracts with customers is disaggregated by type of customer.

		2018		2017
Large users	$	110,904,962	$	115,447,586
Residential		81,625,522		81,658,705
Commercial		24,915,944		24,878,665
Street lights		1,100,590		1,438,130
	$	218,547,018	$	223,423,086

19. Operating expenses

		2018		2017
Salaries and wages	$	10,012,164	$	9,172,514
Depreciation		5,927,266		5,562,586
Benefits		2,897,652		2,295,138
Contracted services/labour		2,728,414		2,793,052
Equipment/building maintenance		1,769,293		1,936,761
Material		882,125		593,837
Other		1,986,366		2,497,006
	$	26,203,280	$	24,850,894

20. Finance income and costs

		2018		2017
Finance income				
Interest income – bank deposits	$	228,209	$	127,902
Finance costs				
Interest expense – long-term debt		2,913,516		2,946,605
Interest expense – operating		72,000		72,000
		2,985,516		3,018,605
Net finance costs recognized in profit or loss	$	2,757,307	$	2,890,703

21. Commitments and contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General liability insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members. All members of the pool could potentially be subjected to an assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2018, no such assessments have been made.

Hydro One Networks Inc. cost recovery

The Corporation is party to a connection and cost recovery agreement ("CCRA") with Hydro One Networks Inc. ("HONI"). This agreement was entered into to have HONI construct a transformer station for the purpose of serving the Corporation's customers including future anticipated electricity load growth. The Corporation was required to make a capital contribution to HONI for the construction of the transformer station and committed to a certain level of electricity load over the next 25 years. The agreement provides for a review of the actual load compared to forecasted load every 5 years ("true-up"). If the actual load is less than the forecasted load for the period, a further capital contribution would be required. The true-up after the first 5 years, shows that the actual load on the transformer station is less than the forecasted load. This could result in a true up payment if this actual shortfall in load continues for the 25 years of the agreement. As a result, no liability has been recorded under this agreement.

22. Operating leases

The Corporation is committed to lease agreements for various vehicles and equipment.

The future minimum non-cancellable annual lease payments are as follows:

	2018	2017
Less than one year	$ 73,369	$ 72,772
Between one and five years	74,447	147,816
	$ 147,816	$ 220,588

During the year ended December 31, 2018 an expense of $72,772 (2017 – $72,285) was recognized in net income in respect of operating leases.

23. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Burlington Hydro Electric Inc., which in turn is wholly-owned by the City. The City produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties

	2018	2017
City of Burlington	$ 47,878,608	$ 47,878,608

(c) Transactions with parent

During the year the Corporation paid management and business development fees to its parent in the amount of $70,001 (2017 – $79,239).

(d) Transactions with ultimate parent (the City)

The Corporation had the following significant transactions with its ultimate parent, a government entity:

During the year, the Corporation earned gross revenue of $3,855,816 (2017 – $4,462,588) from the City. Of this amount, $450,886 (2017 – $471,418) was net distribution revenue.

Amounts payable to and receivable from related parties are non-interest bearing with no fixed terms of repayment.

The Corporation delivers electricity to the City throughout the year for the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

23. Related party transactions (continued)

(e) Transactions with entities under common control

The Corporation received $399,321 (2017 – $395,685) for billing and administrative services from a company under common control.

The Corporation received $57,922 (2017 - $58,471) for general and administrative services from companies under common control.

The Corporation purchased services from a company under common control in the amount of $102,000 (2017 – $102,000) during the year.

The Corporation received $201,743 (2017 – $4,583) for control room services from a company under common control.

(f) Key management personnel

The key management personnel of the Corporation and the Board of Directors were compensated as follows:

	2018	2017
Salaries and other compensation	$ 1,406,043	$ 1,320,064
Short term employee benefits	340,851	342,515
Directors' fees	70,001	79,239
	$ 1,816,895	$ 1,741,818

24. Financial instruments and risk management

Fair value disclosure

The carrying values of cash, securities held as customer deposits, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2018 is $84,164,000. The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rates used to calculate fair value at December 31, 2018 ranged from 3.18% to 3.69% based upon the outstanding term of the loan.

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

24. Financial instruments and risk management (continued)

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Burlington. No single customer accounts for a balance in excess of 2% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of a provision for expected credit losses and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the provision for expected credit losses at December 31, 2018 is $230,000 (2017 – $200,000). An impairment loss of $438,377 (2017 – $69,323) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2018, approximately $737,161 (2017 – $680,018) is considered 60 days past due. The Corporation has over 66 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2018, the Corporation holds security deposits in the amount of $3,835,064 (2017 – $3,623,166).

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $10,000,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2018, no amounts had been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $18,000,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $nil has been drawn and posted with the IESO (2017 – $nil).

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

24. Financial instruments and risk management (continued)

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2018, shareholder's equity amounts to $83,314,711 (2017 – $80,900,515) and long-term debt amounts to $67,618,466 (2017 – $61,633,703).

25. Comparative Information

Certain 2017 comparative figures have been reclassified to conform with the financial statement presentation adopted for the current year.

Appendix F – 2019 Non-Consolidated Audited Financial Statements

Financial Statements of

BURLINGTON HYDRO INC.

And Independent Auditors' Report thereon

Year ended December 31, 2019

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton Ontario L8P 4W7
Canada
Telephone (905) 523-8200
Fax (905) 523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Burlington Hydro Inc.

Opinion

We have audited the financial statements of Burlington Hydro Inc. (the Entity), which comprise:

- the statement of financial position as at December 31, 2019
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity’s ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity’s financial reporting process.

Auditors’ Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors’ report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
March 23, 2020

BURLINGTON HYDRO INC.

Statement of Financial Position

Year ended December 31, 2019, with comparative information for 2018

	Note	2019	2018
Assets			
Current assets			
Cash		$ 4,945,443	$ 13,967,146
Securities held as customer deposits	5	3,898,230	3,835,064
Accounts receivable	6	16,546,122	18,069,407
Work in progress		704,966	625,027
Unbilled revenue		23,544,011	19,941,776
Income taxes receivable		165,206	265,320
Material and supplies	7	5,316,430	4,566,351
Prepaid expenses		525,356	511,754
Total current assets		55,645,764	61,781,845
Non-current assets			
Right-of-use assets	10	417,076	437,557
Property, plant and equipment	8	140,509,543	129,274,931
Intangible assets	9	9,826,964	6,967,387
Deferred tax assets	11	7,737,219	6,078,843
		158,490,800	142,758,718
Total assets		214,136,564	204,540,563
Regulatory balances	12	24,651,404	21,503,996
Total assets and regulatory balances		$ 238,787,968	$ 226,044,559

BURLINGTON HYDRO INC.

Statement of Financial Position

Year ended December 31, 2019, with comparative information for 2018

	Note	2019	2018
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	13	$ 18,259,073	$ 14,621,422
Current portion of lease liabilities	10	113,638	253,459
Current portion of long-term debt	14	1,327,400	1,273,824
Customer deposits	5	3,898,230	3,835,064
Work order deposits		4,536,058	4,985,112
Deferred revenue		1,514,244	1,714,235
Other liabilities		2,363,046	3,755,831
Total current liabilities		32,011,689	30,438,947
Non-current liabilities			
Deferred revenue	15	23,304,474	17,568,377
Deferred tax liabilities	11	10,785,217	8,010,729
Long-term lease liabilities	10	101,572	16,897
Long-term debt	14	64,747,451	66,074,286
Liability for future benefits	16	4,489,718	4,870,343
Total non-current liabilities		103,428,432	96,540,632
Total liabilities		135,440,121	126,979,579
Equity			
Share capital	17	45,139,138	45,139,138
Paid-up capital		876,228	876,228
Retained earnings		40,599,391	37,845,969
Accumulated other comprehensive loss		(181,690)	(546,624)
Total equity		86,433,067	83,314,711
Total liabilities and equity		221,873,188	210,294,290
Regulatory balances	12	16,914,780	15,750,269
Total liabilities, equity and regulatory balances		$238,787,968	$ 226,044,559

See accompanying notes to the financial statements.

On behalf of the Board:

_____________________________ Director _____________________________ Director

BURLINGTON HYDRO INC.

Statement of Comprehensive Income

Year ended December 31, 2019, with comparative information for 2018

	Note	2019	2018
Revenue			
Distribution revenue		$ 31,140,120	$ 30,706,157
Other operating revenue		2,817,558	3,093,155
		33,957,678	33,799,312
Sale of electricity		193,222,328	187,840,861
Total revenue	18	227,180,006	221,640,173
Operating expenses			
Operations and maintenance		9,633,584	9,772,267
Billing and customer service		2,718,123	3,108,174
General administration		8,276,897	7,395,573
Depreciation and amortization		6,316,605	5,927,266
	19	26,945,209	26,203,280
Cost of power purchased		193,448,741	189,166,371
Total expenses		220,393,950	215,369,651
Income from operating activities		6,786,056	6,270,522
Net finance costs	20	(2,896,685)	(2,757,307)
Income before income taxes		3,889,371	3,513,215
Income taxes			
Current	11	137,843	310,758
Future	11	984,548	1,413,041
		1,122,391	1,723,799
Net income after income taxes		2,766,980	1,789,416
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		4,749,877	4,914,627
Other comprehensive income			
Remeasurements of liability for future benefits, net of tax		364,934	249,569
Total comprehensive income		$ 5,114,811	$ 5,164,196

See accompanying notes to the financial statements.

BURLINGTON HYDRO INC.

Statement of Changes in Equity

Year ended December 31, 2019, with comparative information for 2018

	Share capital	Contributed surplus	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2018	$ 45,139,138	$ 876,228	$ 35,681,342	$ (796,193)	$ 80,900,515
Net income and net movement in regulatory balances	-	-	4,914,627	-	4,914,627
Other comprehensive income	-	-	-	249,569	249,569
Dividends	-	-	(2,750,000)	-	(2,750,000)
Balance at December 31, 2018	$ 45,139,138	$ 876,228	$ 37,845,969	$ (546,624)	$ 83,314,711
Balance at January 1, 2019	$ 45,139,138	$ 876,228	$ 37,845,969	$ (546,624)	$ 83,314,711
Transitional adjustment (note 4)	-	-	3,545	-	3,545
Adjusted balance at January 1, 2019	45,139,138	876,228	37,849,514	(546,624)	83,318,256
Net income and net movement in regulatory balances	-	-	4,749,877	-	4,749,877
Other comprehensive income	-	-	-	364,934	364,934
Dividends	-	-	(2,000,000)	-	(2,000,000)
Balance at December 31, 2019	$ 45,139,138	$ 876,228	$ 40,599,391	$ (181,690)	$ 86,433,067

See accompanying notes to the financial statements.

BURLINGTON HYDRO INC.

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	$ 4,749,877	$ 4,914,627
Adjustments for:		
Depreciation and amortization	6,316,605	5,927,266
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	296,159
Net finance costs	2,896,685	2,757,307
Income tax expense	1,122,391	1,723,799
Contributions received from customers	6,214,033	3,151,664
Change in non-cash operating working capital:		
Accounts receivable	1,523,285	1,677,071
Work in progress	(79,939)	(367,475)
Unbilled revenue	(3,602,235)	(1,138,079)
Materials and supplies	(750,079)	(1,116,227)
Prepaid expenses	(13,602)	(64,878)
Accounts payable and accrued liabilities	3,637,651	(3,207,450)
Work order deposits	(449,054)	1,430,697
Deferred revenue	(199,991)	849,017
Other liabilities	(1,392,785)	(379,859)
	19,693,321	16,131,243
Regulatory balances	(1,982,897)	(3,125,211)
Income tax paid	(245,081)	(479,710)
Income tax received	207,352	1,300,129
Interest paid	(3,315,765)	(3,084,667)
Interest received	419,081	327,359
Net cash from operating activities	14,776,011	11,069,143
Investing activities		
Purchase of property, plant and equipment	(16,861,372)	(12,224,179)
Proceeds on disposal of property, plant and equipment	34,468	46,258
Purchase of intangible assets	(3,500,329)	(1,259,014)
Net cash used by investing activities	(20,327,233)	(13,436,935)
Financing activities		
Dividends paid	(2,000,000)	(2,750,000)
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 in financing activities	(3,470,481)	3,234,763
Change in cash	(9,021,703)	866,971
Cash, beginning of year	13,967,146	13,100,175
Cash, end of year	$ 4,945,443	$ 13,967,146

See accompanying notes to the financial statements.

1. Reporting entity

Burlington Hydro Inc. is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the City of Burlington ("City"). The address of the Corporation's registered office is 1340 Brant Street, Burlington, Ontario, L7R 3Z7.

The Corporation delivers electricity and related energy services to residential and commercial customers in the City of Burlington. The Corporation is wholly owned by Burlington Enterprises Corporation ("BEC") formerly Burlington Hydro Electric Inc. and the ultimate parent company is the City.

The financial statements are for the Corporation as at and for the year ended December 31, 2019.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on March 23, 2020.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(d) Rate regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

2. Basis of presentation (continued)

(d) Rate regulation (continued)

Rate setting

Distribution revenue

For distribution revenue, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners, and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“OEB Inflation”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application on October 2, 2013 for rates effective May 1, 2014 to April 30, 2015. In 2019, the Corporation’s cohort ranking with the OEB remained in Group 2 which provides a stretch factor of 0.15%. This resulted in a net adjustment to rates on May 1, 2019 of 1.35% (2018 - 1.05%) comprised of the OEB Inflation for 2019 of 1.50% (2018 - 1.20%), the Corporation's productivity factor of 0.0% (2018 - 0.0%), and the stretch factor of 0.15% (2018 - 0.15%). The Corporation is preparing to file its COS application in August 2020 for rates effective May 1, 2021.

The OEB issued a new distribution rate design for residential electricity customers which was being phased in over a four year period commencing January 2016 with the final phase in 2019. Under this new policy, electricity distributors were to structure residential rates so that all distribution charges are collected through a full fixed monthly charge instead of the fixed and variable rate charges. Burlington Hydro incorporated this final year transition adjustment in its May 1, 2019 OEB approved rates and now has a fully fixed distribution charge for its residential customer.

2. Basis of presentation (continued)

(d) Rate regulation (continued)

Electricity rates - Commodity

The OEB sets electricity prices for certain low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity or pursuant to their contract with a retailer. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

The OEB issued an Accounting Guidance on February 21, 2019 to standardize the accounting processes used by electricity distributors to improve the accuracy of settlements with the IESO for low-volume consumers. The standardization seeks to facilitate the accurate disposition of commodity pass-through variance account balances. The Corporation implemented these procedures by the due date of August 31, 2019 retroactive to January 1, 2019 as required by the OEB.

(e) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Notes 3(d) and (e) – estimation of useful lives of its property, plant and equipment and intangible assets
(ii) Note 3(i) – recognition and measurement of regulatory balances
(iii) Note 3(k), 10 – measurement of leases: discount rate
(iv) Note 11 – classification of taxes between current and deferred
(v) Note 16 – measurement of defined benefit obligations: key actuarial assumptions
(vi) Note 3(h), 21 – recognition and measurement of provisions and contingencies

2. Basis of presentation (continued)

(e) Use of estimates and judgments (continued)

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

(i) Note 3(k) – leases: whether an arrangement contains a lease
(ii) Note 3(k) – leases: lease term, underlying leased asset value
(iii) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment of the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash consists of balances held with financial institutions.

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order to receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other operating revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance are presented as deferred revenue.

Government grants and the related performance incentive payments under CDM (“Conservation and Demand Management”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Significant accounting policies (continued)

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Years
Buildings	10 - 50
Sub-station buildings	50
Sub-station equipment	20 - 40
Distribution lines – overhead	20 - 60
Distribution lines – underground	30 - 60
Distribution – transformers	40
Distribution – meters	15 - 45
Rolling stock	8 - 20
Tools and equipment	10 - 15
Office equipment	10
Computer equipment	5

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated amortization. All intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Asset	Years
Computer software	5
Land rights	35 - 70
Transformer station right	60

3. Significant accounting policies (continued)

(f) Impairment

(i) Financial assets measured at amortized cost

A loss provision for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss provision is measured at an amount equal to the lifetime expected credit losses for the asset. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the impairment requirements is no longer met.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies, and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

3. Significant accounting policies (continued)

(i) Regulatory balances

Regulatory debit balances represent costs incurred in excess of amounts billed to the customer. Regulatory credit balances represent amounts billed to the customer in excess of costs incurred by the Corporation.

Regulatory debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or Other Comprehensive Income ("OCI"). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory debit balances is assessed annually based upon the likelihood that the OEB will approve rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized as a loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities.

The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

3. Significant accounting policies (continued)

(j) Post-employment benefits (continued)

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contained a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

3. Significant accounting policies (continued)

(k) Leased assets (continued)

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash balances.

Finance costs comprise interest expense on borrowings, lease liabilities and customer deposits and are recognized in profit or loss.

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Change in accounting policy (Modified Retrospective approach)

The Corporation has applied IFRS 16 *Leases* with a date of initial application of January 1, 2019. The Corporation applied IFRS 16 using the modified retrospective approach, under which the cumulative effect of initial application is recognized in retained earnings at January 1, 2019. The details of the changes in accounting policies are disclosed below.

Except for the changes below, the Corporation has consistently applied the accounting policies to all periods presented in these financial statements.

Previously, the Corporation determined, at contract inception, whether an arrangement is or contains a lease under IFRIC 4. Under IFRS 16, the Corporation assesses whether a contract is or contains a lease based on the definition of a lease, as explained in Note 3(k). On transition to IFRS 16, the Corporation elected to apply the practical expedient to grandfather the assessment of which contracts are leases. It applied IFRS 16 only to contracts that were previously identified as leases. Contracts that were not identified as leases under IAS 17 and IFRIC 4 were not reassessed for whether they contained a lease. Therefore, the definition of a lease under IFRS 16 was applied only to contracts entered into or changed on or after January 1, 2019.

As a lessee, the Corporation previously classified leases as operating or finance leases based on its assessment of whether the lease transferred significantly all of the risks and rewards incidental to ownership of the underlying asset to the Corporation. Under IFRS 16, the Corporation recognizes right-of-use assets and lease liabilities for most leases – i.e. these leases are on-balance sheet. The Corporation has decided to apply recognition exemptions to short-term leases and leases for which the value of the underlying asset is of low value.

Leases previously classified as operating leases under IAS 17

At transition, lease liabilities were measured at the present value of the remaining lease payments, discounted at the Corporation's incremental borrowing rate as at January 1, 2019. Right-of-use assets are measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments.

4. Change in accounting policy (Modified Retrospective approach) (continued)

The Corporation used the following practical expedients and recognition exemptions when applying IFRS 16 to leases previously classified as operating leases under IAS 17.

— Applied the exemption not to recognize right-of-use assets and liabilities for leases with less than 12 months of lease term;

— Applied the exemption not to recognize right-of-use assets and liabilities for leases for which the underlying asset is of low value;

— Applied this standard to all contracts that were previously identified as leases by applying IAS 17 *Leases* and IFRIC 4 *Determining whether and Arrangement contains a Lease*;

— Elected not to separate non-lease components from lease components, accounting for each lease component and associated non-lease components as a single lease component;

— Excluded initial direct costs from measuring the right-of-use asset at the date of initial application;

— Used hindsight when determining the lease term if the contract contains options to extend or terminate the lease;

— Relied on its assessment of whether leases are onerous under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* immediately before the date of initial application instead of performing an impairment review.

Leases previously classified as finance leases

For leases that were classified as finance leases under IAS 17, the carrying amount of the right-of-use assets and the lease liabilities at January 1, 2019 are determined at the carrying amount of the leased assets and lease liabilities under IAS 17 immediately before that date.

Impacts on financial statements

On transition to IFRS 16, the Corporation recognized an additional $145,623 of right-of-use assets and $142,078 of lease liabilities, recognizing the difference in retained earnings. When measuring lease liabilities, the Corporation discounted lease payments using its incremental borrowing rate or the rate implicit in the lease at January 1, 2019. The rate ranged from 1.90% to 3.99%.

		January 1, 2019
Operating lease commitment at December 31, 2018 as disclosed in the Corporations' financial statements	$	147,816
Discounted using the incremental borrowing at January 1, 2019		5,736
Lease liabilities recognized at January 1, 2019	$	142,080

5. Securities held as customers deposits

The OEB requires companies to periodically review customers' deposits and where appropriate, refund such deposits. During this review, companies may also request a deposit from customers based on certain criteria.

The Corporation has a policy of funding customers' deposits and paying interest on these deposits at a rate determined quarterly. Securities held as customers' deposits represent the funds segregated to fund the customer deposit refunds. The average rate of interest paid by the Corporation for 2019 was 1.95% (2018 – 1.70%).

6. Accounts receivable

	2019	2018
Customer trade receivables	$ 13,685,940	$ 15,458,130
Receivables from the City	170,385	581,454
Receivables from other related parties	4,155	9,312
Other	2,855,642	1,790,511
	16,716,122	17,839,407
Less: Provision for expected credit losses	170,000	230,000
	$ 16,546,122	$ 18,069,407

7. Materials and supplies

The amount written down due to obsolescence in 2019 was $290 (2018 – $14,580).

8. Property, plant and equipment

	January 1, 2019	Additions/ Depreciation	Transitional Adjustment	Disposals/ Retirements	December 31, 2019
Cost					
Land	$ 299,003	$ -	$ -	$ -	$ 299,003
Buildings	5,609,044	826,105	-	-	6,435,149
Sub-station buildings	1,257,417	67,264	-	-	1,324,681
Sub-station equipment	6,300,449	124,258	-	-	6,424,707
Distribution lines – overhead	49,653,603	5,711,869	-	2,547	55,362,925
Distribution lines – underground	44,113,667	7,515,671	-	-	51,629,338
Distribution – transformers	27,171,532	1,563,464	-	97,446	28,637,550
Distribution – meters	13,183,534	509,428	-	94,696	13,598,266
Rolling stock	1,952,570	234,504	-	129,336	2,057,738
Tools and equipment	321,036	9,566	-	-	330,602
Office equipment	700,446	145,115	-	-	845,561
Computer equipment	672,536	154,128	-	44,537	782,127
	151,234,837	16,861,372	-	368,562	167,727,647
Accumulated Depreciation					
Buildings	1,315,045	306,950	-	-	1,621,995
Sub-station buildings	324,510	63,788	-	-	388,298
Sub-station equipment	1,619,440	289,616	-	-	1,909,056
Distribution lines – overhead	5,717,291	1,419,848	-	543	7,136,596
Distribution lines – underground	4,261,448	1,183,950	-	-	5,445,398
Distribution – transformers	3,382,663	856,169	-	65,276	4,173,556
Distribution – meters	4,409,480	979,029	-	56,605	5,331,904
Rolling stock	112,904	198,857	-	84,590	227,171
Tools and equipment	183,246	30,198	-	-	213,444
Office equipment	270,650	79,712	-	-	350,362
Computer equipment	363,229	101,632	-	44,537	420,324
	21,959,906	5,509,749	-	251,551	27,218,104
Carrying amount	$ 129,274,931	$ 11,351,623	$ -	$ 117,011	$140,509,543

8. Property, plant and equipment (continued)

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Land	$ 299,003	$ -	$ -	$ -	$ 299,003
Buildings	5,156,213	452,831	-	-	5,609,044
Sub-station buildings	1,249,684	7,733	-	-	1,257,417
Sub-station equipment	6,003,427	297,022	-	-	6,300,449
Distribution lines – overhead	45,444,828	4,227,972	-	19,197	49,653,603
Distribution lines – underground	39,841,821	4,272,078	-	232	44,113,667
Distribution – transformers	25,815,845	1,444,132	-	88,445	27,171,532
Distribution – meters	13,221,734	611,728	-	649,928	13,183,534
Rolling stock	1,818,554	571,509	-	437,493	1,952,570
Tools and equipment	310,937	10,099	-	-	321,036
Office equipment	646,377	60,230	-	6,161	700,446
Computer equipment	403,691	268,845	-	-	672,536
	140,212,114	12,224,179	-	1,201,456	151,234,837
Accumulated Depreciation					
Buildings	1,038,574	276,471	-	-	1,315,045
Sub-station buildings	257,951	66,559	-	-	324,510
Sub-station equipment	1,300,066	319,374	-	-	1,619,440
Distribution lines – overhead	4,418,797	1,306,756	-	8,262	5,717,291
Distribution lines – underground	3,201,279	1,060,262	-	93	4,261,448
Distribution – transformers	2,616,118	821,581	-	55,036	3,382,663
Distribution – meters	3,761,997	1,005,910	-	358,427	4,409,480
Rolling stock	368,074	175,888	-	431,058	112,904
Tools and equipment	150,904	32,342	-	-	183,246
Office equipment	205,352	71,459	-	6,161	270,650
Computer equipment	286,586	76,643	-	-	363,229
	17,605,698	5,213,245	-	859,037	21,959,906
Carrying amount	$ 122,606,416	$ 7,010,934	$ -	$ 342,419	$129,274,931

No interest was capitalized to property, plant and equipment during the year.

Assets with a carrying amount of $140,509,543 (2018 – $129,274,931) are subject to a general security agreement.

9. Intangible assets

	January 1, 2019	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2019
Cost					
Land rights	$ 160,008	$ -	$ -	$ -	$ 160,008
Computer software	4,425,767	1,727,529	-	-	6,153,296
Transformer station right	5,079,322	1,772,800	-	-	6,852,122
	9,665,097	3,500,329	-	-	13,165,426
Accumulated Depreciation					
Land rights	13,832	2,520	-	-	16,352
Computer software	2,332,744	538,232	-	-	2,870,976
Transformer station right	351,134	100,000	-	-	451,134
	2,697,710	640,752	-	-	3,338,462
Carrying amount	$ 6,967,387	$ 2,859,577	$ -	$ -	$ 9,826,964

	January 1, 2018	Additions/ Depreciation	Transfers	Disposals/ Retirements	December 31, 2018
Cost					
Land rights	$ 160,008	$ -	$ -	$ -	$ 160,008
Computer software	4,166,753	259,014	-	-	4,425,767
Transformer station right	4,079,322	1,000,000	-	-	5,079,322
	8,406,083	1,259,014	-	-	9,665,097
Accumulated Depreciation					
Land rights	11,312	2,520	-	-	13,832
Computer software	1,800,189	532,555	-	-	2,332,744
Transformer station right	274,240	76,894	-	-	351,134
	2,085,741	611,969	-	-	2,697,710
Carrying amount	$ 6,320,342	$ 647,045	$ -	$ -	$ 6,967,387

10. Lease liabilities

	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

	Vehicles	Computer software	Total
Lease liabilities			
Balance at January 1, 2019	$ 186,375	$ 83,981	$ 270,356
Transitional adjustment	97,453	44,625	142,078
Repayment	(95,015)	(102,209)	(197,224)
Balance at December 31, 2019	$ 188,813	$ 26,397	$ 215,210
At December 31, 2018	$ 186,375	$ 83,981	$ 270,356

Effective January 1, 2019, the Corporation adopted IFRS 16 and transitioned its operating leases to finance leases. The leased assets secures 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).

Total cash outflows with respect to leasing arrangements during the year was $211,658 (2018 - $220,627) consisting of principal and interest of $197,224 and $14,434, respectively (2018 - $202,985, $17,642).

The Corporation has a lease commitment for which the underlying asset value has been determined by the Corporation to be less than $5,000 USD. This asset has not been accounted for under IFRS 16 *Leases* due to their low value. As such, the Corporation has expensed $1,280 (2018 - $1,295) in profit or loss during the year for this lease.

Certain leases held by the Corporation provide the Corporation with extension options and termination options that may impact the term of the Lease which can impact the lease liabilities recognized in the statement of financial position. The Corporation has determined the lease term for all contracts based on all available information as at the reporting date.

10. Lease liabilities (continued)

Lease liabilities are due as follows:

	Less than one year	Between one and five years	More than five years	Total
Future minimum lease payments				
December 31, 2019	$ 121,325	$ 105,180	$ -	$ 226,505
December 31, 2018	259,926	17,417	-	277,343
Interest				
December 31, 2019	7,687	3,610	-	11,297
December 31, 2018	6,419	55	-	6,474
Present value of minimum lease payments				
December 31, 2019	113,638	101,572	-	215,210
December 31, 2018	253,459	16,897	-	270,356

11. Income tax expense

Current tax expense

	2019	2018
Current period	$ (226,743)	$ 294,319
Prior period adjustments	364,586	16,439
	$ 137,843	$ 310,758

Deferred tax expense

	2019	2018
Origination and reversal of temporary differences	$ 984,548	$ 1,413,041
Tax adjustment included in other comprehensive income	131,566	89,980
	$ 1,116,114	$ 1,503,021

Reconciliation of effective tax rate

	2019	2018
Income before taxes	$ 3,889,371	$ 3,513,215
Canada and Ontario statutory income tax rates	26.50%	26.50%
Expected tax provision on income at statutory rates	1,030,683	931,002
Increase (decrease) in income taxes resulting from:		
Permanent differences	5,232	6,456
Under provided in prior periods	4,677	139,922
Regulatory	92,326	621,591
Other adjustments	(10,527)	24,828
Income tax expense	$ 1,122,391	$ 1,723,799

Significant components of the Corporation’s deferred tax balances

	2019	2018
Deferred tax (liabilities) assets:		
Property, plant and equipment	$ (9,515,811)	$ (6,852,066)
Intangible assets	(295,919)	(232,148)
Post-employment benefits	1,189,857	1,290,641
Regulatory deferral account balances	(973,487)	(926,515)
Deferred revenue	6,175,686	4,655,620
Other	371,676	132,582
	$ 3,047,998	$ (1,931,886)

11. Income tax expense (continued)

The Company underwent an audit in 2019 for the 2014 and 2015 taxation years. Upon completion of the audit, the Ministry reassessed and adjusted the classification of smart meter assets. For taxation years prior to 2014, the Ministry agreed with the Company's classification of such assets as filed in its tax returns. The Company has chosen to accept the Ministry's classification of these assets and believes it is probable that the tax authorities will propose a similar adjustment for taxation years subsequent to 2015. Accordingly, the Company has recorded an increase in the current tax expense and a decrease in the future tax expense, relating to the 2016 to 2018 taxation years. For 2019, the Company has classified these assets consistent with the Ministry's reassessments brought forth in 2019.

Subsequent to the Company's audit of the 2014 and 2015 taxation years in 2019, the Company became aware that the Ministry had also changed its assessing practice with respect to certain current period deductions claimed by the Company. The Ministry did not raise this issue during their audit of the Company's 2014 and 2015 taxation years. The Company believes it is probable that the Ministry will continue to accept its filing position with respect to this item. If the tax authorities applied this change for the years 2016-2019 there would be an increase in current taxation expense and a decrease in future taxation expense. The net impact on the financial statements would be nil as the adjustments are related to the timing of when deductions are permitted.

The Company is confident that its accruals for tax liabilities are adequate.

12. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining recovery/ reversal years
Group 1 deferral accounts	$ 4,141,974	$187,331,125	$ (186,705,466)	$ 4,767,633	2
Regulatory settlement account	12,801,567	9,915	737,677	13,549,159	2
Other regulatory accounts	2,131,860	646,672	(209,261)	2,569,271	2
Income tax	2,428,595	1,336,746	-	3,765,341	-
	$ 21,503,996	$189,324,458	$ (186,177,050)	$ 24,651,404	

Regulatory deferral account debit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining recovery/ reversal years
Group 1 deferral accounts	$ 4,354,710	$171,118,267	$ (171,331,003)	$ 4,141,974	2
Stranded meter cost	59,743	-	(59,743)	-	-
Regulatory settlement account	20,428,907	10,923	(7,638,263)	12,801,567	1
Other regulatory accounts	1,180,701	985,151	(33,992)	2,131,860	3
Income tax	1,649,012	779,583	-	2,428,595	-
	$ 27,673,073	$172,893,924	$ (179,063,001)	$ 21,503,996	

Regulatory deferral account credit balances	January 1, 2019	Additions	Recovery/ reversal	December 31, 2019	Remaining years
Group 1 deferral accounts	$ (1,961,899)	$ 6,196,974	$ (6,600,917)	$ (2,365,842)	2
Regulatory settlement account	(13,762,248)	(37,539)	-	(13,799,787)	2
Other regulatory accounts	(26,122)	(278,668)	(444,361)	(749,151)	2
	$ (15,750,269)	$ 5,880,767	$ (7,045,278)	$ (16,914,780)	

Regulatory deferral account credit balances	January 1, 2018	Additions	Recovery/ reversal	December 31, 2018	Remaining years
Group 1 deferral accounts	$ (3,622,269)	$ 18,112,078	$ (16,451,708)	$ (1,961,899)	2
Regulatory settlement account	(21,322,439)	(39,657)	7,599,848	(13,762,248)	1
Other regulatory accounts	(99,849)	(274)	74,001	(26,122)	3
	$ (25,044,557)	$ 18,072,147	$ (8,777,859)	$ (15,750,269)	

The income tax balances will be recovered over the life of the related capital assets.

12. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using historical data. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

The Corporation seeks authorization to settle the Group 1 deferral accounts through application to the OEB as part of the annual rate application. Settlement is typically done through volumetric rate riders. Since future consumption volumes are impacted by exogenous factors (e.g. weather, economic conditions) the amount actually disposed of through the operation of the authorized rate rider varies from the balance authorized for disposition. The OEB authorized the Corporation to dispose of $(2,157,475) through rate riders which expired on April 30, 2019. In Burlington Hydro's application for rates effective May 1, 2019, the OEB approved its request to defer the disposition of the 2017 Group 1 deferral account balances until its next rate application. An application has since been made to the OEB to dispose of $(371,075) of Group 1 deferral account balances for 2017 and 2018; approval for which is pending. Once approval is received, the approved account balance will be moved to the regulatory settlement account.

The Corporation received OEB decision on March 28, 2019 for the recovery of the true-up payment to Hydro One on Tremaine TS. Subsequently in a separate application dated October 10, 2019, the Corporation filed another ICM application for the recovery of major capital projects, i.e. Customer Information System and Geographical Information System. The OEB allows electricity distributors to recover such major capital projects through separate rate riders.

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points. In 2019, the average rate was 2.25% (2018 – 1.86%).

13. Accounts payable and accrued liabilities

	2019	2018
IESO – energy purchases	$ 9,405,682	$ 6,426,918
Regional Municipality of Halton	4,806,187	4,713,530
Trade payables	3,922,679	3,421,742
Payable to related parties	124,525	59,232
	$ 18,259,073	$ 14,621,422

14. Long-term debt

	2019	2018
Notes payable	$ 47,878,608	$ 47,878,608
Ontario Infrastructure loan and note	18,196,243	19,469,502
	66,074,851	67,348,110
Current portion	1,327,400	1,273,824
Long-term portion	$ 64,747,451	$ 66,074,286

The notes payable bear interest at 4.88% are unsecured and are due on demand to the City. The City has waived its right to demand payment until January 1, 2021.

The Corporation obtained an Ontario Infrastructure Projects Corporation ("OIPC") Fixed Term Loan of $10,000,000 on March 15, 2011 due March 15, 2026. The loan bears interest at a rate of 4.51%. The loan is payable in the amount of $76,550 monthly principal and interest.

On March 8, 2013, the Corporation obtained a loan from the OIPC in the form of a Promissory Note of $8,000,000 due March 1, 2038. The Note bears interest at a rate of 4.02%. The Note is payable in the amount of $42,315 monthly principal and interest.

On December 17, 2018, the Corporation obtained a loan from the OIPC in the form of a Promissory Note of $7,000,000 due December 17, 2033. The note bears interest at a rate of 3.63%. The note is payable in the amount of $50,490 monthly principal and interest.

The OIPC facilities are secured by a general security agreement over the assets of the Corporation.

Scheduled repayments of long term debt for the years ended December 31 are as follows:

2020	$ 1,327,400
2021	1,383,864
2022	1,442,751
2023	1,504,166
2024	1,568,218
Thereafter	58,848,452
	$ 66,074,851

15. Deferred revenue

Deferred revenue relates to the capital contributions received from customers and others. The amount of deferred revenue received from customers and others is $23,304,474 (2018 - $17,568,377). Deferred revenue is recognized as revenue on a straight-line basis over the life of asset for which the contribution was received.

16. Liability for future benefits

(a) OMERS pension plan

As at December 31, 2019, the OMERS plan was 97% funded (2018 – 96.0%). OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions. In 2019, the Corporation made employer contributions of $1,035,133 to OMERS (2018 – $1,028,087, of which $197,131 (2018 – $174,944) has been capitalized as part of PP&E and the remaining amount of $838,002 (2018 – $853,143) has been recognized in profit or loss. The Corporation estimates that a contribution of $1,161,678 to OMERS will be made in 2020.

(b) Post-employment benefits other than pension

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2019	2018
Defined benefit obligation, beginning of year	$ 4,870,343	$ 5,156,792
Included in profit or loss		
Current service cost	187,154	191,340
Interest cost	184,956	165,168
	5,242,453	5,513,300
Included in OCI		
Actuarial gains arising from:		
Changes in financial assumptions	(496,500)	(339,550)
	(496,500)	(339,550)
Benefits paid	(256,235)	(303,407)
Defined benefit obligation, end of year	$ 4,489,718	$ 4,870,343

Actuarial assumptions	2019	2018
General inflation	2.00%	2.00%
Discount (interest) rate	3.00%	3.90%
Salary levels	2.60%	2.10%
Medical costs	3.50%	3.78%
Dental costs	2.50%	2.50%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $533,000. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $678,000.

17. Share capital

	2019	2018
Authorized:		
Unlimited number of common shares		
Issued:		
2,000 common shares	$ 45,139,138	$ 45,139,138

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid dividends in the year on common shares of $1,000 per share (2018 – $1,375) which amount to total dividends paid in the year of $2,000,000 (2018 – $2,750,000).

18. Revenue

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. Other sources of revenue include performance incentive payments under CDM programs.

	2019	2018
Revenue from contracts with customers	$ 225,748,078	$ 219,844,054
Other revenue		
Collection charges	114,893	462,783
Late payment charges	263,965	304,816
CDM Expenses Recovery / Incentives - Net	468,625	908,308
Other	666,985	416,371
Loss on disposal of property, plant and equipment	(82,540)	(296,159)
Total revenue	$ 227,180,006	$ 221,640,173

18. Revenue (continued)

In the following table, revenue from contracts with customers is disaggregated by type of customer.

	2019	2018
Large users	$ 113,684,108	$ 110,904,962
Residential	83,900,674	81,817,957
Commercial	27,362,756	26,020,545
Street lights	800,540	1,100,590
	$ 225,748,078	$ 219,844,054

19. Operating expenses

	2019	2018
Salaries and wages	$ 9,644,821	$ 10,012,164
Depreciation	6,316,605	5,927,266
Benefits	2,882,255	2,897,652
Contracted services/labour	3,313,047	2,728,414
Equipment/building maintenance	1,868,672	1,769,293
Material	546,046	882,125
Other	2,373,763	1,986,366
	$ 26,945,209	$ 26,203,280

20. Finance income and costs

	2019	2018
Finance income		
Interest income – bank deposits	$ 281,819	$ 228,209
Finance costs		
Interest expense – long-term debt	3,091,873	2,895,874
Interest expense – operating	72,197	72,000
Interest expense – lease liabilities	14,434	17,642
	3,178,504	2,985,516
Net finance costs recognized in profit or loss	$ 2,896,685	$ 2,757,307

21. Commitments and contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General liability insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members. All members of the pool could potentially be subjected to an assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2019, no such assessments have been made.

22. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Burlington Enterprises Corporation, which in turn is wholly-owned by the City. The City produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties

	2019	2018
City of Burlington	$ 47,878,608	$ 47,878,608

(c) Transactions with parent

During the year the Corporation paid management and business development fees to its parent in the amount of $55,110 (2018 – $70,001).

22. Related party transactions (continued)

(d) Transactions with ultimate parent (the City)

The Corporation had the following significant transactions with its ultimate parent, a government entity:

During the year, the Corporation earned gross revenue of $3,463,875 (2018 – $3,662,488) from the City. Of this amount, $388,806 (2018 – $439,671) was net distribution revenue.

Amounts payable to and receivable from related parties included in accounts payable and accounts receivable are non-interest bearing with no fixed terms of repayment.

The Corporation delivers electricity to the City throughout the year for the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

(e) Transactions with entities under common control

The Corporation received $390,267 (2018 – $399,321) for billing and administrative services from a company under common control.

The Corporation received $59,200 (2018 - $57,922) for general and administrative services from companies under common control.

The Corporation purchased services from a company under common control in the amount of $102,000 (2018 – $102,000) during the year.

The Corporation received $110,000 (2018 – $201,743) for control room services from a company under common control.

(f) Key management personnel

The key management personnel of the Corporation and the Board of Directors were compensated as follows:

	2019	2018
Salaries and other compensation	$ 1,443,183	$ 1,406,043
Short term employee benefits	330,360	340,851
Directors' fees	55,110	70,001
	$ 1,828,653	$ 1,816,895

23. Financial instruments and risk management

Fair value disclosure

The carrying values of cash, securities held as customer deposits, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2019 is $100,787,000. The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rates used to calculate fair value at December 31, 2019 ranged from 2.40% to 2.88% based upon the outstanding term of the loan.

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City of Burlington. No single customer accounts for a balance in excess of 2% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of a provision for expected credit losses and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the provision for expected credit losses at December 31, 2019 is $170,000 (2018 – $230,000). An impairment loss of $226,856 (2018 – $438,377) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2019, approximately $524,940 (2018 – $737,161) is considered 60 days past due. The Corporation has over 68 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2019, the Corporation holds security deposits in the amount of $3,898,230 (2018 – $3,835,064).

23. Financial instruments and risk management (continued)

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $10,000,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2019, no amounts had been drawn under the Corporation's credit facility.

The Corporation also has a bilateral facility for $18,000,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $nil has been drawn and posted with the IESO (2018 – $nil).

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2019, shareholder's equity amounts to $86,433,067 (2018 – $83,314,711) and long-term debt amounts to $66,074,851 (2018 – $67,348,110).

24. Comparative Information

Certain 2018 comparative figures have been reclassified to conform with the financial statement presentation adopted for the current year.

Appendix G – Reconciliation Audited Financial Statements with Regulatory Financial Results

BALANCE SHEET

Financial Statement Heading	Financial Statement Line Item	USoA	RRR Balances '000s	Manual Adjustment to RRRs for AFS Purposes	Adjusted Balance for AFS Purposes	Balance per Audited Financial Statements	Difference between 2.1.7 Trial Balance & Financial Statements	Foot Note
Assets								
Current assets	Cash	1005	8,843,073	(3,898,230)	4,945,443	4,945,443	-	**A**
		1010	600					
	Securities held as customer deposits			3,898,230	3,898,230	3,898,230	-	**A**
	Accounts receivable	1100	9,173,894		16,546,122	16,546,122	-	
		1104	647,292					
		1110	6,684,494					
		1130	(170,000)					
		1200	177,412					
		1460	33,030					
	Work in progress	2055	704,966		704,966	704,966	-	
	Unbilled revenue	1120	23,544,011		23,544,011	23,544,011	-	
	Income taxes receivable			165,206	165,206	165,206	-	**A**
	Material and supplies	1305	15,409		5,316,430	5,316,430	-	
		1330	5,301,021					
	Prepaid expenses	1180	457,472	(165,206)	525,356	525,356	-	**A**
	Record 2019 LRAMVA (tax impact)			481,660				**C**
	Amortize 2021 COS costs (tax impact)			(202,596)				**D**
	ICM DVA Trx recorded 2020 internal FS			(25,114)				**E**
	Mthly Billg DVA Trx recorded 2020 internal FS			12,052				**F**
	Coll.Chge DVA Savings recorded 2020 internal FS			(5,603)				**G**
	PILs DVA Rev.Req't recorded 2020 internal FS			(27,309)				**H**
Total current assets			55,412,674	279,064	55,645,764	55,645,764	-	
Non-current assets	Property, plant and equipment	1805	202,703		202,703	140,509,543	-	
		1808	2,538,554		2,538,554			
		1820	14,478,740		14,478,740			
		1830	45,214,302		45,214,302			
		1835	54,906,123		54,906,123			
		1840	25,422,467		25,422,467			
		1845	40,006,007		40,006,007			
		1850	58,954,201		58,954,201			
		1855	42,917,039		42,917,039			
		1860	21,553,146		21,553,146			
		1905	96,300		96,300			
		1908	10,572,660		10,572,660			
		1915	1,886,541		1,886,541			
		1920	1,334,448		1,334,448			
		1930	4,671,764	(679,684)	3,992,080			**B**
		1935	272,397		272,397			
		1940	1,519,313		1,519,313			
		1945	416,690		416,690			
		1955	362,813		362,813			
		1960	26,607		26,607			
		1980	4,317,572		4,317,572			
		1995	(29,277,061)		(29,277,061)			
		2105	(169,291,526)	8,087,427	(161,204,099)			**B**
	Right-of-use assets	1930		679,684	679,684	417,076	-	**B**
		1611		397,503	397,503			**B**
		2105		(660,111)	(660,111)			**B**
	Intangible assets	1609	4,318,402		6,886,402	9,826,964	-	
	ICM DVA Trx recorded 2020 internal FS			2,568,000				**E**
		1611	10,666,993	(397,503)	10,130,364			**B**
	Mthly Billg DVA Trx recorded 2020 internal FS			(139,126)				**F**
		1612	189,351		189,351			
		2105		(7,427,316)	(7,379,153)			**B**
	ICM DVA Trx recorded 2020 internal FS			(21,400)				**E**
	Mthly Billg DVA Trx recorded 2020 internal FS			69,563				**F**
	Deferred tax assets	2350		7,737,217	7,737,217	7,737,217	-	**A**
			148,276,546	10,214,254	158,490,800	158,490,800	-	
Total assets			203,689,220	10,493,318	214,136,564	214,136,564	-	
Regulatory balances	Regulatory assets	1508	4,318,409		1,826,152	24,651,404	-	
	ICM DVA Trx recorded 2020 internal FS			(2,537,483)				**E**
	Mthly Billg DVA Trx recorded 2020 internal FS			24,084				**F**
	Coll.Chge DVA Savings recorded 2020 internal FS			21,142				**G**
		1548	2,559		2,559			
		1568	1,711,748		1,711,748			
	Record 2019 LRAMVA			(1,711,748)	(1,711,748)			**C**
		1584	196,056		196,056			
		1586	651,864		651,864			
		1588	1,239,263		1,239,263			
		1589	2,781,879		2,781,879			
		1572	145,444		145,444			
		1575	595,117		595,117			
		2320	3,765,341		3,765,341			
		1595	13,553,565		13,447,729			
	Record 2019 LRAMVA (apprd + recovries)			(105,836)				**C**
Total assets and regulatory balances			**232,650,465**	**6,183,477**	**238,787,968**	**238,787,968**	**-**	

Financial Statement Heading	Financial Statement Line Item	USoA	RRR Balances '000s	Manual Adjustment to RRRs for AFS Purposes	Adjusted Balance for AFS Purposes	Balance per Audited Financial Statements	Difference between 2.1.7 Trial Balance & Financial Statements	Foot Note
Liabilities								
Current liabilities	Accounts payable and accrued liabilities	2205	(872,290)	360,155	(512,135)	(18,259,073)	-	**A**
		2220	(19,285,933)	2,167,797	(17,118,136)			**A**
		2240	(124,524)		(124,524)			
		2290	(504,278)		(504,278)			
	Current portion of lease liabilities	2260		(113,638)	(113,638)	(113,638)	-	**B**
	Current portion of long-term debt	2260	(1,441,038)	113,638	(1,327,400)	(1,327,400)	-	**B**
	Customer deposits	2210	(3,860,266)		(3,860,266)	(3,898,230)	-	
		2320	(37,964)		(37,964)			
	Work order deposits	2335	(4,024,302)	(511,756)	(4,536,058)	(4,536,058)	-	**A**
	Deferred revenue - current	2440		(1,514,244)	(1,514,244)	(1,514,244)	-	**A**
	Other liabilities	2205		(360,155)	(360,155)	(2,363,046)	-	**A**
		2208	(385,250)		(385,250)			
		2220		(1,656,041)	(1,656,041)			**A**
		2250	47,845		47,845			
		2292	(9,445)		(9,445)			
Total current liabilities			(30,497,445)	(1,514,244)	(32,011,689)	(32,011,689)	-	
Non-current liabilities	Deferred revenue - long-term	2440	(24,818,718)	1,514,244	(23,304,474)	(23,304,474)	-	**A**
	Deferred tax liabilities	2350	(3,048,000)	(7,737,217)	(10,785,217)	(10,785,217)	-	**A**
	Long-term lease liabilities	2325	(101,572)		(101,572)	(101,572)	-	
	Long-term debt	2550	(47,878,608)		(47,878,608)	(64,747,451)	-	
		2520	(16,868,843)		(16,868,843)			
	Liability for future benefits	2306	(4,489,718)		(4,489,718)	(4,489,718)	-	
			(97,205,459)	(6,222,973)	(103,428,432)	(103,428,432)	-	
Total liabilities			(127,702,904)	(7,737,217)	(135,440,121)	(135,440,121)	-	
Equity	Share Capital	3005	(45,139,138)		(45,139,138)	(45,139,138)	-	
	Paid-up capital	3022	(876,228)		(876,228)	(876,228)	-	
	Retained earnings	3045	(36,867,011)		(35,849,513)	(40,599,391)	-	
	Record 2019 LRAMVA (apprd + recovries)			1,109,297				**C**
	Mthly Billg DVA Trx recorded 2020 internal FS			(795)				**F**
	Coll.Chge DVA Savings recorded 2020 internal FS			(91,004)				**G**
		3046	(5,229,041)		(4,749,878)			
	Record 2019 LRAMVA (apprd + recovries)			226,627				**C**
	Amortize 2021 COS costs			202,595				**D**
	ICM DVA Trx recorded 2020 internal FS			15,997				**E**
	Mthly Billg DVA Trx recorded 2020 internal FS			34,222				**F**
	Coll.Chge DVA Savings recorded 2020 internal FS			(15,539)				**G**
	PILs DVA Rev.Req't recorded 2020 internal FS			15,261				**H**
	Accumulated other comprehensive loss	3090	181,690		181,690	181,690		
Total equity			(87,929,728)	1,496,661	(86,433,067)	(86,433,067)	-	
Total liabilities and equity			(215,632,632)	(6,240,556)	(221,873,188)	(221,873,188)	-	
Regulatory balances	Regulatory liabilities	1508	(469,365)		(469,365)	(16,914,780)	-	
		1518	(3,595)		(3,595)			
		1580	(2,390,000)		(2,390,000)			
		1551	(77,271)		(77,271)			
		1592	(379,242)		(276,190)			
	PILs DVA Rev.Req't recorded 2020 internal FS			103,052				**H**
		1595	(13,698,359)		(13,698,359)			
Total liabilities, equity and regulatory balances			**(232,650,464)**	**(6,137,504)**	**(238,787,968)**	**(238,787,968)**	**-**	

A - Reclassification within financial statements
B - Adjustments recognized for IFRS purposes
C - Record 2019 LRAMVA - not recognized in AFS until recoveries received
D - Amortize 2021 COS costs over 5 year rate period - recognized in AFS when expense incurred
E - Adjust 2019 ICM transactions in DVA - booked in 2020 AFS
F - Adjust 2017-2019 Monthly Billing Incremental Costs/Savings transactions in DVA - booked in 2020 AFS
G - Record Collection charge 2019 DVA savings amount - booked in 2020 AFS
H - Record PILs 2018/2019 grossed-up amount in DVA - booked in 2020 AFS

INCOME STATEMENT

Financial Statement Heading	Financial Statement Line Item	USoA	RRR Balances '000s	Manual Adjustment to RRRs for AFS Purposes	Adjusted Balance for AFS Purposes	Balance per Audited Financial Statements	Difference between 2.1.7 Trial Balance & Financial Statements	Foot Note
Revenue								
	Distribution Revenue	4080	(31,192,413)		(31,140,120)	(31,140,120)	-	
	Record 2019 LRAMVA (apprd + recovries)			274,946				C
	Mthly Billg DVA Trx recorded 2020 internal FS			44,391				F
	PILs DVA Rev.Req't recorded 2020 internal FS			23,545				H
	MicroFit S/C Revenue Reallocated			(14,399)				I
	IFRS Adjustment (DVA 1592 revenue)			(276,190)				B
	Other Operating Revenue	4082	(22,890)	22,890	-	(2,817,558)	-	A
		4084	(477)	477	-			A
		4210	(329,782)		(329,782)			
		4220	(9,953)		(9,953)			
		4225	(263,965)		(263,965)			
		4235	(727,126)		(414,977)			
	MicroFit S/C Revenue Reallocated			14,399				I
	IFRS Adjustment (DVA 1508 revenue)			297,750				B
		4245	(477,936)		(477,936)			
		4310	(70,262)		-			
	IFRS Adjustment (DVA 1575 revenue)			70,262				B
		4355	12,278		82,540			
	Loss on Disposal Reclassified			70,262				J
		4375	(600,835)		(435,635)			
	Record Affiliate Control Room revenue			110,000				K
	Record Affiliate Management services revenue			55,200				L
		4380	883,511	(476,979)	146,139			A
	Record Affiliate Control Room expenses			(99,193)				K
	Record Affiliate Management services expenses			(55,200)				L
	Record Affiliate Accounting services expenses			(4,000)				M
	Record Affiliate Co-gen expenses			(102,000)				N
		4390	(1,003,989)		(1,113,989)			
	Record Affiliate Control Room revenue			(110,000)				K
		4405	(508,016)	281,819	(80,414)			A
	IFRS Adjustment (DVA carrying charges)			83,556				B
	Record 2019 LRAMVA (carrying charges)			33,390				C
	ICM DVA Trx recorded 2020 internal FS			365				E
	Mthly Billg DVA Trx recorded 2020 internal FS			29,996				F
	Coll.Chge DVA Savings recorded 2020 internal FS			1,258				G
	PILs DVA Rev.Req't recorded 2020 internal FS			(2,782)				H
		6035		80,414	80,414			A
			(34,311,855)	354,177	(33,957,678)	(33,957,678)	-	
	Sale of Electricity	4006	(45,832,457)		(45,832,457)	(193,222,328)	-	
		4025	(395,293)		(395,293)			
		4035	(97,128,572)		(97,128,572)			
		4055	(20,024,661)		(20,024,661)			
		4062	(5,750,388)		(5,750,388)			
		4066	(11,515,121)		(11,515,121)			
		4068	(10,471,510)		(10,471,510)			
		4076	(446,585)		(446,585)			
	IFRS Adjustment (DVA CoP revenue)			(1,657,741)	(1,657,741)			B
Total revenue			(225,876,442)	(1,303,564)	(227,180,006)	(227,180,006)	-	
Operating expenses	Operations and maintenance	5010	2,150,032		2,250,685	9,633,584	-	
	Record Affiliate Control Room expenses			85,440				K
	Record Affiliate Co-gen expenses			15,213				N
		5012	102,021		102,021			
		5016	227,546		227,546			
		5017	382,272		382,272			
		5020	303,257		303,257			
		5025	491,300		491,300			
		5035	12,964		12,964			
		5040	39,641		39,641			
		5045	307,374		307,374			
		5055	14,478		14,478			
		5065	158,083		158,083			
		5070	270,193		270,193			
		5075	106,631		106,631			
		5110	632,867		632,867			B
		5114	398,030		398,030			
		5120	218,969		218,969			
		5125	1,369,352		1,369,352			
		5130	250,130		250,130			
		5135	596,249		596,249			
		5145	40,303		40,303			
		5150	659,769		659,769			
		5155	459,990		459,990			
		5160	165,628		165,628			
		5175	175,852		175,852			B
	Billing and customer service	5310	359,378		359,378	2,718,123	-	B
		5315	804,981	69,178	882,047			A
	Record Affiliate Co-gen expenses			7,888				N
		5320	259,985		237,585			
	Coll.Chge DVA Savings recorded 2020 internal FS			(22,400)				G
		5330	149,447		149,447			
		5335	102,391	102,059	204,450			A
		5340	602,678	98,889	720,979			A
	Record Affiliate Co-gen expenses			19,412				N
	IFRS Adjustment (DVA 1508/1518/1548 expenses)			164,237	164,237			B

Financial Statement Heading	Financial Statement Line Item	USoA	RRR Balances '000s	Manual Adjustment to RRRs for AFS Purposes	Adjusted Balance for AFS Purposes	Balance per Audited Financial Statements	Difference between 2.1.7 Trial Balance & Financial Statements	Foot Note
	General Administration	5420	15,271		15,271	8,276,897	-	
		5605	2,267,415	55,110	2,322,525			A
		5610	47,595		47,595			
		5615	2,036,685		2,036,685			
		5620	472,084		472,084			
		5625	(343,703)	128,376	(197,574)			A
	Record Affiliate Control Room expenses			13,753				K
	Record Affiliate Accounting services expenses			4,000				M
		5630	734,670		734,670			
		5635	29,206		29,206			
		5640	142,069		142,069			
		5645	372,200		372,200			
		5655	236,127		511,767			
	Amortize 2021 COS costs (5 yr period)			275,640				D
		5660	90,408		90,408			
		5665	794,455		794,455			
		5675	347,667		407,154			
	Record Affiliate Co-gen expenses			59,487				N
		6105	331,720		331,720			
		6205	86,538		86,538			
	IFRS Adjustment (1508 DVA expenses)			80,124	80,124			B
	Depreciation and amortization	5705	6,393,292		6,316,605	6,316,605	-	
	ICM DVA Trx recorded 2020 internal FS			21,400				E
	Mthly Billg DVA Trx recorded 2020 internal FS			(27,825)				F
	Loss on Disposal Reclassified			(70,262)				J
			25,865,490	1,156,406	26,945,209	26,945,209	-	
	Cost of power purchased	4705	85,146,095		85,146,095	193,448,741	-	
		4707	78,234,889		78,234,889			
		4708	5,750,388		5,750,388			
		4714	11,515,121		11,515,121			
		4716	10,471,510		10,471,510			
		4751	446,585		446,585			
	IFRS Adjustment (DVA CoP expenses)			1,884,153	1,884,153			B
Total expenses			217,430,078	3,040,559	220,393,950	220,393,950	-	
Income from operating activities			(8,446,364)	1,736,995	(6,786,056)	(6,786,056)	-	
	Net finance costs	6005	2,408,673		2,408,673	2,896,685	-	
		6035	850,245	(80,414)	769,831			A
		4405		(281,819)	(281,819)			A
Income before income taxes			(5,187,446)	1,374,762	(3,889,371)	(3,889,371)	-	
	Income taxes							
	Current	6110	310,603		137,843	137,843	-	
	Record 2019 LRAMVA (tax impact)			(81,710)				C
	Amortize 2021 COS costs (tax impact)			(73,045)				D
	ICM DVA Trx recorded 2020 internal FS			(5,768)				E
	Mthly Billg DVA Trx recorded 2020 internal FS			(12,338)				F
	Coll.Chge DVA Savings recorded 2020 internal FS			5,603				G
	PILs DVA Rev.Req't recorded 2020 internal FS			(5,502)				H
	Future	6115	(352,198)		984,548	984,548	-	
	IFRS Adjustment (Tax on DVA movement)			1,336,746				B
			(41,595)	1,163,986	1,122,391	1,122,391	-	
Net income after income taxes			(5,229,041)	2,538,748	(2,766,980)	(2,766,980)	-	
Net movement in regulatory balances, net of tax	Net movement in regulatory balances			(646,151)	(646,151)	(646,151)	-	B
	Income tax on net movement in regulatory balances			(1,336,746)	(1,336,746)	(1,336,746)	-	B
			-	(1,982,897)	(1,982,897)	(1,982,897)	-	
							-	
Net income and net movement in regulatory balances			(5,229,041)	555,851	(4,749,877)	(4,749,877)	-	
Other comprehensive income	Remeasurement of liability for future benefits	7010	(496,500)		(496,500)	(364,934)	-	
	(net of tax)	7025	131,566		131,566			
Total comprehensive income			(5,593,975)	555,851	(5,114,811)	(5,114,811)	-	

A - Reclassification within financial statements
B - Adjustments recognized for IFRS purposes
C - Record 2019 LRAMVA - not recognized in AFS until recoveries received
D - Amortize 2021 COS costs over 5 year rate period - recognized in AFS when expense incurred
E - Adjust 2019 ICM transactions in DVA - booked in 2020 AFS
F - Adjust 2017-2019 Monthly Billing Incremental Costs/Savings transactions in DVA - booked in 2020 AFS
G - Record Collection charge 2019 DVA savings amount - booked in 2020 AFS
H - Record PILs 2018/2019 grossed-up amount in DVA - booked in 2020 AFS
I - Reallocate MicroFit S/C revenue to Other Operating revenue
J - Reclassify Loss on Disposal from 4360 to 5705 for OEB reporting and rate application filings
K - Reallocate Affiliate Control Room revenue and expenses
L - Record Affiliate Management services revenue and expenses
M - Reallocate Affiliate Accounting services expenses
N - Reallocate Affiliate Co-gen expenses

Appendix H – BHI 2019 Community Report

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	241	38	68
utility poles installed in 2019	new service connections in 2019	overhead transformer banks installed in 2019	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

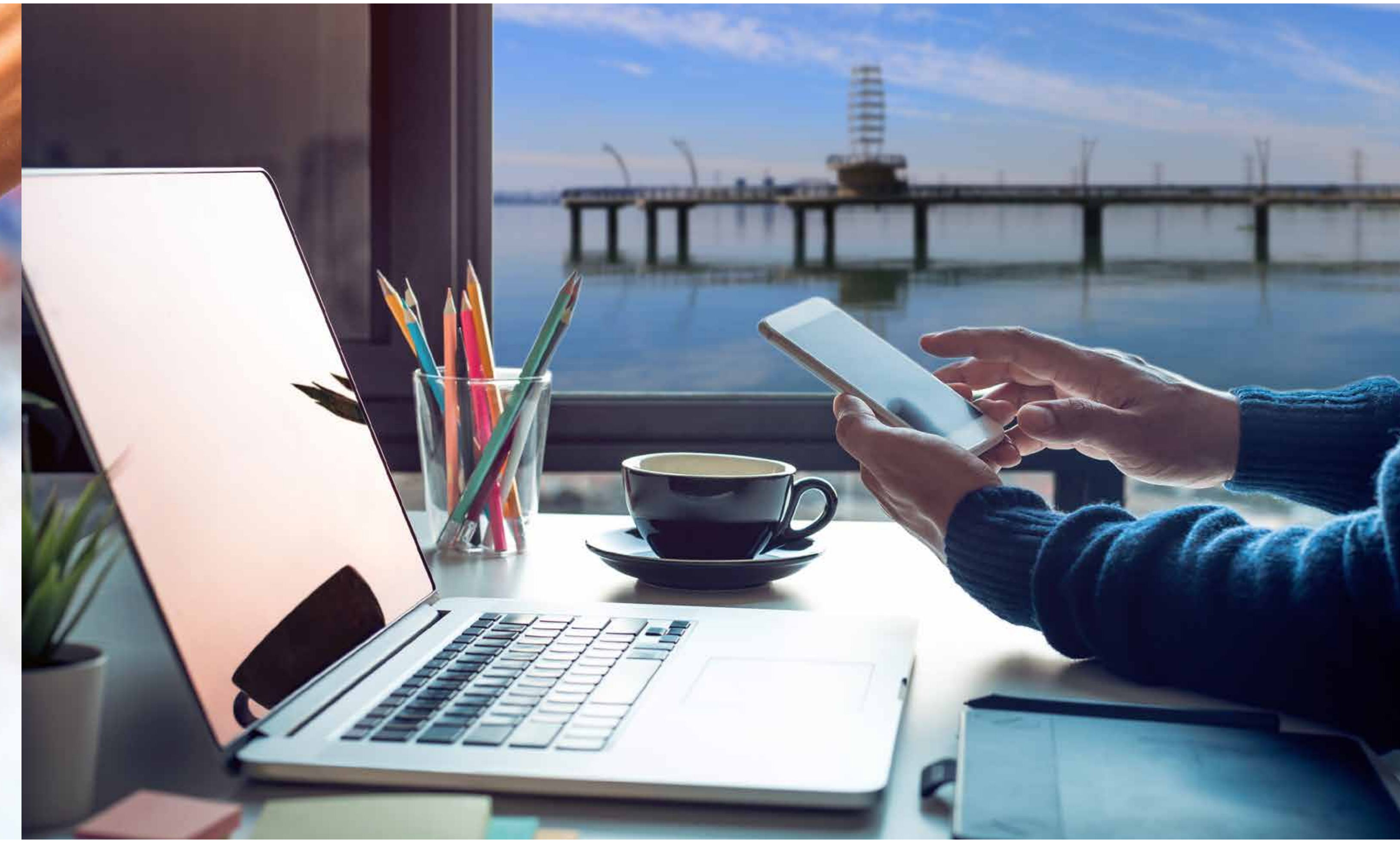
Burlington Hydro maintains a vigilant focus on cyber risk in order to ensure the integrity of its operations, processes and business systems. The company continues to evolve their Information Security Management Program in alignment with the Ontario Cyber Security Framework for electricity utilities 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)

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.

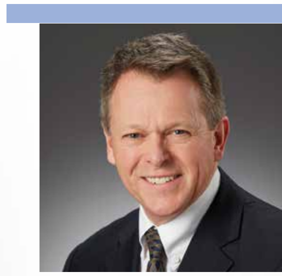
The integration of Dayforce is modernizing our approach to communicating with employees, while reducing our environmental footprint with the reduction/elimination of paper records.

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

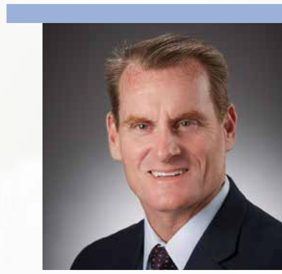


John Maheu
Chair

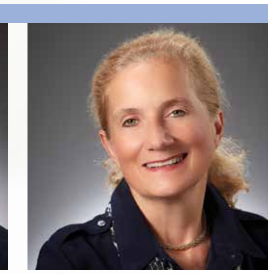
Mayor
Marianne Meed Ward

Susan Kilburn

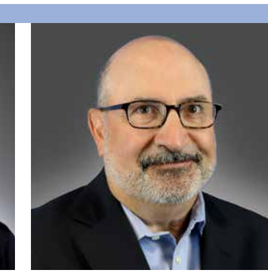
Sherry Smith



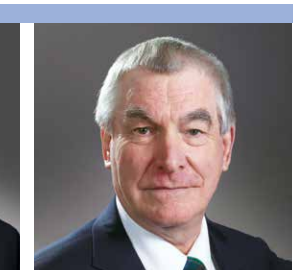
David Kerr



Patricia Volker

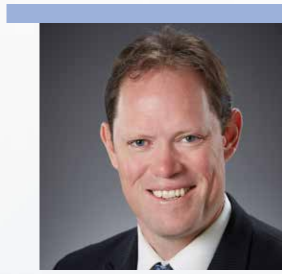


Tim Commisso

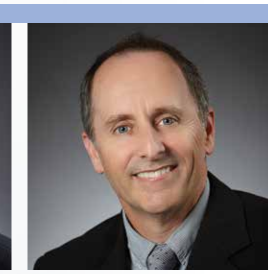


Archie Bennett

leadership team

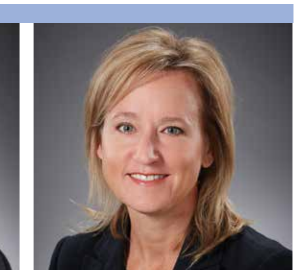


Gerry Smallegange
President and Chief Executive Officer

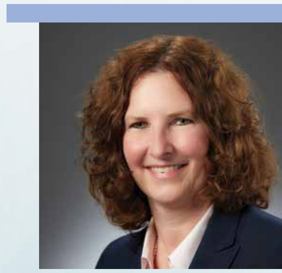


Michael Kysley
Executive Vice President and Chief Financial Officer

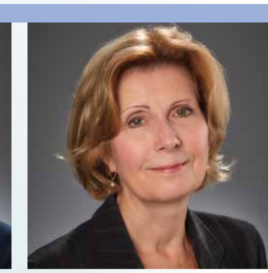
Dan Guatto
Vice President, Engineering and Operations, and Chief Operating Officer



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.

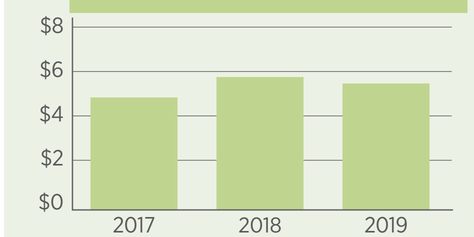
Financial Highlights For the year ended December 31 (Canadian $ in millions)	**2019**	**2018**
Financial Results		
Gross Revenue	228.5	225.5
Operating Expenses	21.1	23.1
Net Income	5.6	5.9
Balance Sheet Information		
Total Assets	216.2	206.7
LT Debt less current maturities	64.7	66.1
Total Shareholder's 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

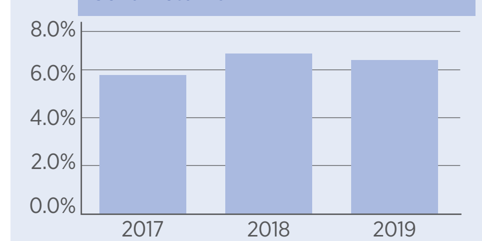
Net Income $5.6 million
Stable Earnings (millions)



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.

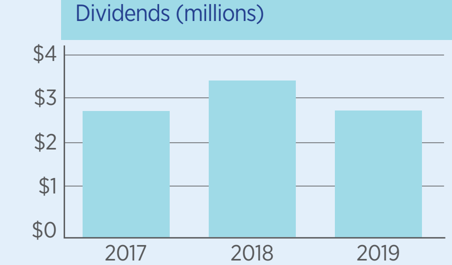
Return On Equity 6.4%
Solid Returns



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.

75 YEARS

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