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November 24, 2021

Delivered by Email & RESS

Ms. Christine Long, Registrar
Ontario Energy Board
P.O.Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: North Bay Hydro Distribution Limited and Espanola Regional Hydro Distribution Corporation
MAADs Application under Section 86 of the *Ontario Energy Board Act, 1998* and Related Relief

We are counsel to North Bay Hydro Distribution Limited ("**NBHDL**") and Espanola Regional Hydro Distribution Corporation ("**ERHDC**") (collectively, the "**Applicants**") for the above-noted matter.

Please find enclosed an application (the "**Application**") made by the Applicants for leave to amalgamate NBHDL and ERHDC into an entity referred to in the Application as "New NBHDL", pursuant to section 86(1)(c) of the *Ontario Energy Board Act*, *1998*, and other relief as described under Section 2 of the Application.

Please do not hesitate to contact the undersigned if you have any questions.

Yours very truly,
BORDEN LADNER GERVAIS LLP
Per:

Flora Ho
cc: Melissa Casson, Vice President of Finance, NBHDL
Matt Payne, President and Chief Executive Officer, ERHDC

ONTARIO ENERGY BOARD

IN THE MATTER OF Sections 86 and 18 of the *Ontario Energy Board Act*, *1998* S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application for leave to amalgamate North Bay Hydro Distribution Limited and Espanola Regional Hydro Distribution Corporation, into an entity referred to in this Application as "New NBHDL", made pursuant to section 86(1)(c) of the *Ontario Energy Board Act*, *1998* and other relief as described under Section 2 of this application.

APPLICATION

Filed: November 24, 2021

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Certification of Evidence

As President and Chief Executive Officer of both North Bay Hydro Distribution Limited and Espanola Regional Hydro Distribution Corporation and in my capacity as an officer of these corporations and without personal liability, I hereby certify to the best of my knowledge and as at the date of this certification that the evidence in the Application is accurate, consistent and complete.

Matt Payne, President and Chief Executive Officer

APPLICATION

1. Introduction

This is an application by North Bay Hydro Distribution Limited ("**NBHDL**") and Espanola Regional Hydro Distribution Corporation ("**ERHDC**") (collectively, the "**Applicants**"), to the Ontario Energy Board (the "**OEB**") under Section 86(1)(c) of the *Ontario Energy Board Act, 1998* ("**OEB Act**") for an order granting leave to amalgamate NBHDL and ERHDC, into New NBHDL and the additional approvals as set out in Section 2 below (the "**Application**").

This Application is organized to generally follow the order of requirements for consolidation applications as set out in the Board's *Handbook to Electricity Distributor and Transmitter Consolidations* (the "**Handbook**"). The mapping of evidence provided at Appendix A pinpoints the exact location of the evidence responsive to each of the Board's requirements. This Application is consistent with the Handbook as well as the Board's March 26, 2015 *Report of the Board on Rate-Making Associated with Distributor Consolidation* (the "**Consolidation Report**").

1.1 Background

On January 16, 2019, North Bay (Espanola) Acquisition Inc. ("**NBEAI**") (an affiliate of NBHDL) filed a Mergers, Amalgamations, Acquisitions and Divestitures ("**MAADs**") application (EB-2019-0015) ("**Phase 1 Application**") which sought approval for the acquisition of Espanola Hydro Holdings Corporation ("**ERHHC**") and Espanola Regional Hydro Distribution Corporation ("**Old ERHDC**") by NBEAI and the amalgamation of NBEAI, ERHHC and Old ERHDC to form Espanola Regional Hydro Distribution Corporation ("**ERHDC**"). These approvals formed Phase 1 of the two-phased transaction.

In its August 22, 2019 Decision and Order ("**MAADs Decision**"), the OEB approved the transaction described in the Phase 1 Application. Effective October 1, 2019, NBEAI, ERHHC and Old ERHDC amalgamated pursuant to the provisions of the *Business Corporations Act, 1990* (Ontario) ("**OBCA**"), to continue as one corporation under the name of "Espanola Regional Hydro Distribution Corporation". ERHDC is one of the Applicants in this Application.

Consistent with the rate making framework proposed in the Phase 1 Application, NBHDL and ERHDC continue to operate separately on a stand-alone basis. ERHDC filed its 2021 Cost of Service application on December 31, 2020 (EB-2020-0020) and a Decision and Rate Order was issued on June 10, 2021 ("**ERHDC COS Decision**"). NBHDL filed its own Cost of Service application (EB-2020-0043) and a Decision and Order was issued on September 9, 2021 ("**NBHDL COS Decision**").[1]

As explained in the Phase 1 Application,[2] upon completion of the ERHDC Cost of Service Application and the NBHDL Cost of Service Application, NBHDL will bring an application to the OEB to approve Phase 2 of the transaction to allow for the amalgamation of NBHDL and ERHDC under Section 86(1)(c) of the OEB Act.

This MAADs Application constitutes what was referred to as the Phase 2 application in the Phase 1 Application and in the MAADs Decision.[3]

As described in the Phase 1 Application, ERHDC is currently party to a services agreement with PUC Services Inc. ("**PUC**") effective June 1, 2016, as amended (the "**PUC Services Agreement**"), pursuant to which PUC provides a comprehensive suite of management services, customer services and IT services to support the day-to-day operations of ERHDC. The term of the PUC Services Agreement is set to expire February 28, 2022. The timing of this Application is intended to facilitate a transition period to allow for the orderly and timely transition of services from PUC to New NBHDL prior to the expiry of the PUC Services Agreement.

In the event the approvals sought in this Application are delayed or the transaction to create New NBHDL is not completed prior to March 1, 2022, the services will instead be transitioned to NBHDL and a new Affiliate Relationships Code ("**ARC**") compliant services agreement will be

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[1] On September 23, 2021 Donald D. Rennick ("**Mr. Rennick**") served a Motion to Review and Vary the NBHDL COS Decision (EB-2021-0251) (the "**Motion**"). The OEB issued a Decision and Order on October 21, 2021 and denied the Motion. On November 9, 2021, Mr. Rennick filed a Motion to Review and Vary the Decision and Order on Motion dated October 21, 2021 ("**Second Motion**"). At the time of this Application, the OEB has not yet issued a Decision to the Second Motion.
[2] Phase 1 Application at page 13.
[3] EB-2019-0015 - Decision and Order dated August 22, 2019 ("**MAADs Decision**"), page 4.

entered into between NBHDL and ERHDC to cover the interim period prior to completion of the transaction.

1.2 Items from ERHDC COS Decision and NBHDL COS Decision to be Addressed

The following two items from the ERHDC COS Decision and NBHDL COS Decision and one item from the MAADs Decision are relevant to this Application:

1. In the ERHDC COS Decision, the OEB approved the Settlement Proposal filed by ERHDC, in which the parties to the Settlement Proposal agreed that:

   "Espanola Regional Hydro would either: a) file an application with the OEB to amalgamate Espanola Regional Hydro with North Bay Hydro Distribution Limited with one year of the issuance of the Final Rate Order in this proceeding; or b) file a new cost of service rebasing application with a five year Distribution System Plan within two years of the issuance of the Final Rate Order in this proceeding – under this option Espanola Regional Hydro would not be entitled to a Price-Cap IR formulaic increase to distribution rates in 2022."[4]

   The OEB noted this condition in its findings.[5]

2. In the NBHDL COS Decision, with respect to Earnings Sharing Mechanism ("**ESM**"), the OEB found that "the ESM issue would be more appropriately addressed as part of the MAADs application expected in 2022 to merge with Espanola Hydro."[6]

3. In the MAADs Decision, the OEB made the following order:

   "The Applicant's preliminary review has not identified material differences in the underlying accounting policies between North Bay Hydro and Espanola Hydro. The

[4] EB-2020-0020, Espanola Regional Hydro Distribution Corporation, Decision and Order dated June 10, 2021 ("**ERHDC COS Decision**") at page 3 and 4.
[5] ERHDC COS Decision at page 5.
[6] EB-2020-0043, North Bay Hydro Distribution Limited, Decision and Order dated September 9, 2021, at page 34.

Applicant is ordered to complete its analysis of accounting policies and bring forward a detailed proposal as part of its cost of service rate application."[7]

In response to item 1 above, this Application is being filed within one year of the issuance of the Final Rate Order of the ERHDC COS proceedings (i.e. on or before June 9, 2022).

In response to item 2, the Applicants have included their proposal on ESM at Section 8.2 in this Application.

Item 3 has already been addressed in the ERHDC COS proceedings. As stated in the Settlement Proposal in that ERHDC COS proceedings the parties to that proceeding agreed that ERHDC has responded appropriately to the OEB's order in EB-2019-0015 that ERHDC complete an analysis on the differences in accounting policies between ERHDC and NBHDL. The parties agreed that nothing further is required as a result of this analysis on accounting policies.[8] The Settlement Proposal was accepted by the OEB in the ERHDC COS Decision.[9] Therefore, no further action is required in the Application to address item 3.

1.3 The Proposed Amalgamation

NBHDL and ERHDC have completed their respective rebasing applications for 2021 rates. In anticipation of the transition of services from PUC to NBHDL, and the expiry of the PUC Services Agreement on February 28, 2022, this Application is to seek approval to allow for the amalgamation of NBHDL and ERHDC under section 86(1)(c) of the OEB Act (the **"Proposed Amalgamation").**

As a result of the Phase 1 Application, NBHDL and ERHDC are now both wholly-owned subsidiary corporations of North Bay Hydro Holdings Limited ("**NBHHL**"). Section 177(2) of the OBCA provides that two or more wholly-owned subsidiary corporations of the same holding body corporate may amalgamate and continue as one corporation without complying with sections

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[7] MAADs Decision at page 27.
[8] ERHDC COS Decision, Schedule B, June 10, 2021 at page 42.
[9] ERHDC COS Decision at page 1.

175 and 176 of the OBCA provided that the amalgamation is approved by a resolution of the directors of each amalgamating corporation and the resolution requirements are met. Therefore, no formal amalgamation agreement is required. The board resolutions completed, executed and passed by the directors of NBHHL, NBHDL and ERHDC to approve the amalgamation are attached as Appendix B.

With respect to the consideration to be given and received by each of the parties to the Proposed Amalgamation, the shares of ERHDC will be cancelled without repayment of capital in accordance with Section 177(2)(b)(i) of the OBCA.

The stated capital of the amalgamating subsidiary corporations whose shares are cancelled (i.e. ERHDC) will be added to the stated capital of the amalgamating subsidiary corporation whose shares are not cancelled (i.e. NBHDL).

The following Figure 1-1 and 1-2 illustrates the proposed corporate ownership structure pre-amalgamation and post-amalgamation (i.e. completion of the Proposed Amalgamation):

Figure 1-1: Corporate Ownership Structure Prior to Proposed Amalgamation

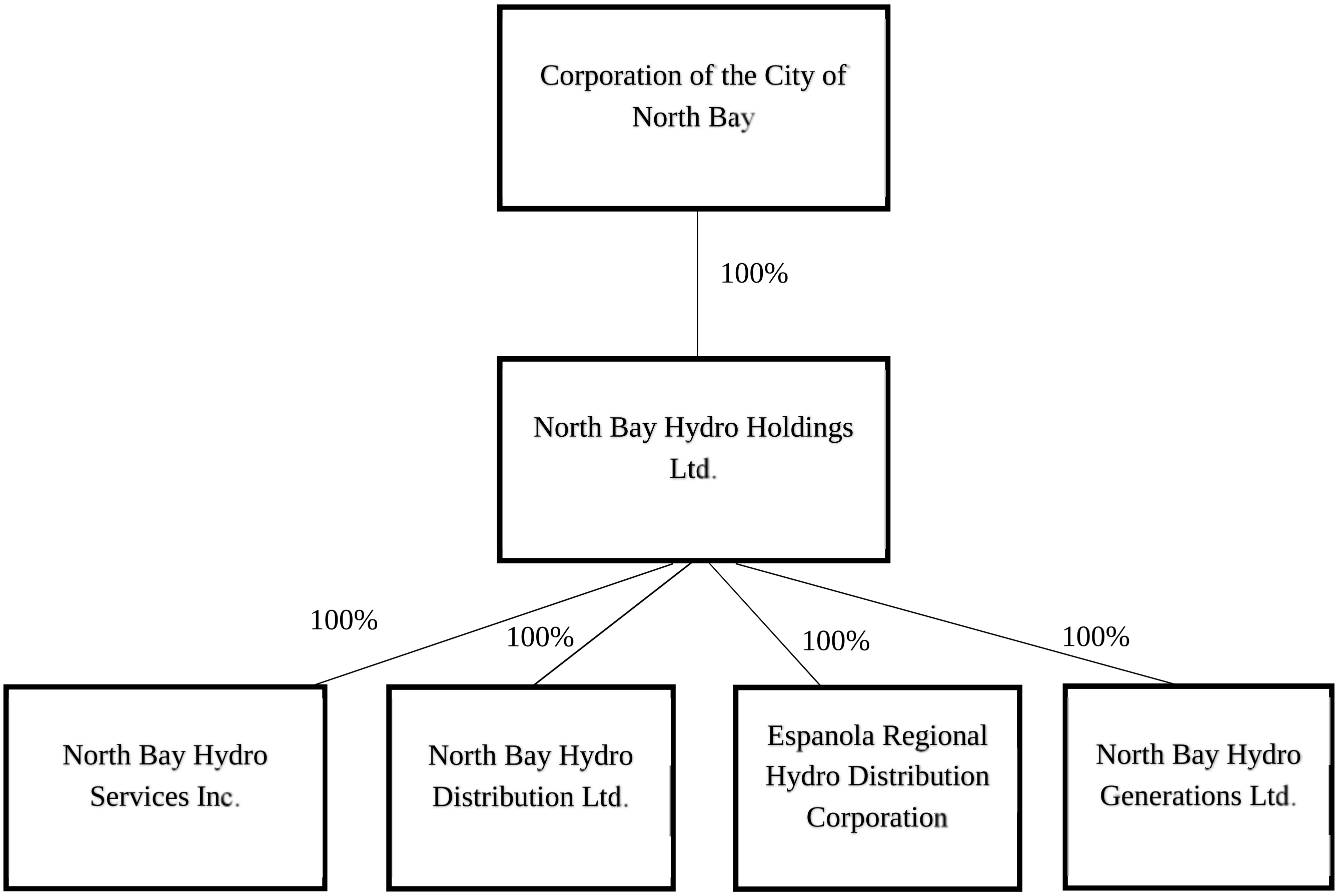
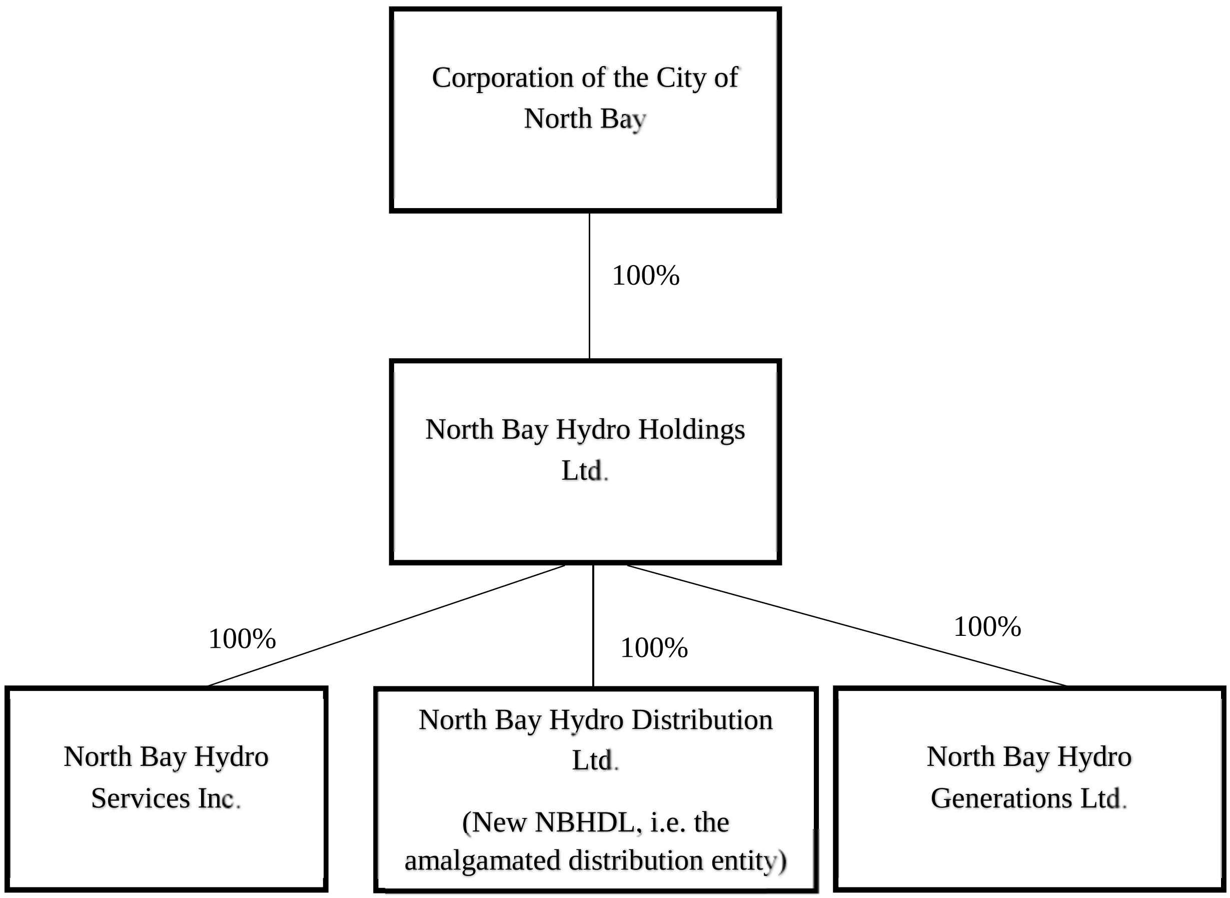


Figure 1-2: Corporate Ownership Structure After Proposed Amalgamation



The amalgamated entity will operate under the name North Bay Hydro Distribution Limited (referred to in this Application as New NBHDL).

According to the OEB's Performance standards for processing applications,[10] the OEB's performance standard for processing *Mergers, Acquisitions, Amalgamations and Divestitures - Section 86 (change of ownership or control of utilities and assets)* applications is 180 calendar days from the issuance of completeness letter to final decision (in the case of an oral hearing) and 130 calendar days (in the case of a written hearing).

[10] Ontario Energy Board, Performance standards for processing applications, effective April 1, 2021. Available online: https://www.oeb.ca/industry/applications-oeb/performance-standards-processing-applications (last accessed: August 26, 2021).

Therefore, the Applicants expects that the timing of the OEB's Decision and Order in this proceeding will follow the expiration of the PUC Services Agreement.

For the period of time after the expiration of PUC Services Agreement and before the OEB's Decision and Order in this proceeding, NBHDL will enter into an ARC compliant services agreement with ERHDC.

In addition, as part of a condition to the Settlement Proposal in ERHDC's Cost of Service proceedings (EB-2020-0020), it was agreed that ERHDC would either: a) file an application with the OEB to amalgamate ERHDC and NBHDL within one year of the issuance of the Final Rate Order in that proceeding; or b) file a new cost of service rebasing application with a five year Distribution System Plan within two years of the issuance of the Final Rate Order in this proceeding – under this option Espanola Regional Hydro would not be entitled to a Price-Cap IR formulaic increase to distribution rates in 2022.[11] As the Final Rate Order was issued on June 10, 2021, in order to pursue option (a), this Application would need to be filed on or before June 9, 2022. The Applicants have met this condition with this Application.

In the Phase 1 Application, NBHDL committed to only defer rebasing and rate harmonization of New NBHDL for five (5) years following the Phase 2 transaction.[12] In addition, in the Reply Submissions in the Phase 1 Application, NBEAI submitted a proposal regarding ESM. Specifically, NBEAI proposed to include an ESM that would share overearnings 300 basis points above the OEB-approved return on equity ("**ROE**") on a 50:50 basis with ratepayers beginning in year six following the closing of the Phase 1 transaction.[13] This is consistent with the ESM proposal in this Application, as set out in Section 8.2 below.

[11] EB-2020-0020 – Espanola Regional Hydro Distribution Corporation, Decision and Rate Order dated June 10, 2021 at page 3 and 4.
[12] Phase 1 Application at pages 14, 25 and 37.
[13] EB-2019-0015 North Bay (Espanola) Acquisition Inc. Reply Submissions dated July 12, 2019 at page 6 and 7.

NBEAI notified the OEB of the closing of the Phase 1 transaction on October 1, 2019.[14] Therefore, year six following the closing would be starting October 1, 2025, which is when the ESM is proposed to commence.

2. OEB Approval Requests

The Applicants hereby apply to the OEB for the following approvals:

(a) Leave for NBHDL and ERHDC to amalgamate and continue as a corporation referred to as New NBHDL, pursuant to Section 86(1)(c) of the OEB Act;

(b) Leave to transfer the current and any future rate orders and rate riders of ERHDC to New NBHDL pursuant to Section 18 of the OEB Act;

(c) Approval for New NBHDL to continue to track costs to existing deferral and variance accounts;

(d) An order to amend NBHDL's distribution licence (ED-2003-0024) pursuant to Section 74 of the OEB Act to include ERHDC's service territory, to be effective on the completion of the amalgamation and to be followed immediately by the cancellation of the distribution licence of ERHDC (ED-2002-0502) pursuant to Section 77(5) of the OEB Act.

The Applicants respectfully request that this Application be heard by way of a written hearing.

3. The No Harm Test

The Handbook states that to demonstrate no harm, applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve customers following a consolidation will be no higher than they would otherwise have been. The Handbook also states

[14] EB-2019-0015 – Letter from NBEAI to OEB Re: Securities Purchase Agreement dated October 12, 2018 between The Corporation of the Town of Espanola, The Corporation of the Township of Sables-Spanish Rivers, North Bay Hydro Holdings Ltd. and North Bay (Espanola) Acquisition Inc. dated October 1, 2019.

that the impact the Proposed Amalgamation will have on economic efficiency and cost effectiveness will be assessed based on an applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

As will be demonstrated in this Application, the Proposed Amalgamation passes the "no-harm" test as the evidence demonstrates that the amalgamation is expected to have a positive effect on the attainment of the OEB's statutory objectives as follows:

- The Proposed Amalgamation is forecasted to positively impact the customers of NBHDL and ERHDC with respect to price, adequacy, reliability, and quality of electricity service due to the efficiencies expected to be generated from the amalgamation:
  - The PUC Services Agreement will be expiring on February 28, 2022 and subsequent to the expiry of the Services Agreement, New NBHDL will be taking over the provision of these services. The transition work has begun for New NBHDL to be in a position to assume the services currently provided by PUC to ERHDC under the PUC Services Agreement on March 1, 2022 with support from PUC as needed until June 30, 2022. New NBHDL will have an ARC compliant services agreement put in place under the assumption that the amalgamation date with ERHDC is currently unknown, but anticipated to occur some time in 2022. The services agreement will effectively mimic the PUC Services Agreement. In the event the approvals sought in this Application are delayed or the transaction to create New NBHDL is not completed prior to March 1, 2022, the services will instead be transitioned to NBHDL and an ARC compliant services agreement will be entered into between NBHDL and ERHDC to cover the interim period prior to completion of the transaction.
  - The cost synergies and operational efficiencies that will be realized in the underlying OM&A costs upon amalgamation of NBHDL and ERHDC will be driven principally by the cancellation of the PUC Services Agreement. Prior to the amalgamation, NBHDL will need to charge ERHDC for the provision of these

services in accordance with its obligations under ARC. Subsequent to the Proposed Amalgamation, the OM&A per customer in 2027 for New NBHDL would be $353.57, which is 39.8% less for ERHDC and 1.2% less for NBHDL (see Sections 6.1 and 7.1).

- Synergies that will arise from the amalgamation itself represent approximately 30% of the forecasted synergies. Benefits include eliminating costs where duplication exists in both businesses, typical of the centralization of back-office functions.
- The amalgamation will also result in the integration of engineering and operational expertise between ERHDC and NBHDL, which will lead to higher quality operations and maintenance plans that will benefit customers of both NBHDL and ERHDC (see Sections 6.1).
- The amalgamation will not affect the source of electricity supply for either NBHDL and ERHDC (see Section 6.2).
- Transition costs for the Proposed Amalgamation are anticipated to be approximately $215,000 and transaction costs are approximately $85,000 and both of these will be funded entirely through retained earnings, not rates (see Section 7.2).

- The Proposed Amalgamation incorporates the benefits to be realized through voluntary amalgamation; it will deliver cost synergies and economy of scale benefits contemplated by the Ontario Distribution Sector Review Panel and will promote the objectives contained in the OEB's Renewed Regulatory Framework.
- New NBHDL will continue to promote the education of customers.
- The promotion of electricity conservation and demand management will continue to be a focus of both LDCs and the ultimate amalgamated distribution entity.
- New NBHDL will continue to facilitate the implementation of a smart grid in Ontario.
- New NBHDL will continue to promote the use and generation of electricity from renewable sources and will continue to reinforce the distribution systems throughout its service

territories in order to accommodate the connection of renewable energy generation facilities.

The OEB has acknowledged that consolidation enables distributors to address challenges in an evolving electricity industry. The Proposed Amalgamation promotes the objectives of the *OEB's Renewed Regulatory Framework for Electricity Distributors – A Performance Based Approach*. The Proposed Amalgamation impacts are anticipated to be positive.

There are no anticipated adverse impacts and, as such, the Applicants submit that the Proposed Amalgamation meets the Board's "No Harm" test.

4. Details of the Authorized Representatives of the Applicants

The Applicant requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

a) The Applicants

NBHDL
Melissa Casson, CPA, CGA
Vice President of Finance
74 Commerce Crescent
North Bay, ON P1A 0B4
Phone: 705-474-8100 ext: 300
Fax: 705-474-8579
Email: mcasson@northbayhydro.com

ERHDC
Matt Payne, President and Chief Executive Officer
Espanola Regional Hydro Distribution Corporation
598 Second Street, Espanola, Ontario, P5E 1C4
Phone: 705-474-8100 ext: 259
Fax: 705-474-8579

Email: mpayne@northbayhydro.com

b) Counsel to the Applicants

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5. Description of the Business of the Parties to the Amalgamation

5.1 Business of each of the parties to the Proposed Amalgamation

North Bay Hydro Distribution Limited

NBHDL is a licensed electricity distributor (ED-2003-0024) that owns and operates the electricity distribution system that provides service to approximately 24,290 mostly residential and commercial electricity customers in the City of North Bay. NBHDL is a corporation incorporated pursuant to the OBCA with its head office in the City of North Bay.

NBHHL is the sole owner of North Bay Hydro Services Inc., NBHDL, ERHDC, and North Bay Hydro Generations Ltd. (“**NBHGL**”). NBHHL is, in-turn, solely owned by the City of North Bay.

NBHDL is embedded in Hydro One Network Inc.’s (“**HONI**”) 44 kV sub transmission system at the City of North Bay’s water treatment plant located at 248 Lakeside Dr. and at substation #17, which is located in North Bay’s rural area at 20 Peninsula Road. Hydro One is embedded in NBHDL’s 44kV sub transmission system at Bond St., also known as Wood’s junction. HONI is also embedded in NBHDL’s 12 kV distribution system at the northern city limits of North Bay on Highway 11 North.

NBHDL does not have any transmission or high voltage assets (>50kV) deemed previously by the Board as distribution assets.

Espanola Regional Hydro Distribution Corporation

ERHDC is a licensed electricity distributor that owns and operates the electricity distribution system that serves approximately 3,328 electricity customers in the Town of Espanola and the Township of Sables-Spanish Rivers. ERHDC’s office is located in the Town of Espanola.

ERHDC is embedded in 5 sections of HONI’s distribution network.

- ERHDC supply to the majority of the Town of Espanola is embedded in HONI 44 kV subtransmission system with supply points on west side of the town near 936 Second Ave and 665 Barber Street.

- ERHDC supply to Old Webbwood Rd and Lee Valley Rd embedded in HONI 12.5kV distribution with supply point at the intersection of Old Webbwood Rd & Rogers Rd and terminating west of 2201 Lee Valley Rd.

- ERHDC supply to Jacklin Rd & Dupuis Rd embedded in HONI 12.5kV distribution system with supply point east of 377 Jacklin Rd.

- ERHDC supply to Town of Massey embedded in HONI 12.5 kV distribution system with supply point on west side of town near 395 Castle Street.
- ERHDC supply to the Town of Webbwood embedded in HONI 12.5 kV distribution system with supply point on west side of town near 52 Young St.

ERHDC does not host any utilities within its service area.

ERHDC does not have any transmission or high voltage assets (>50kV) deemed previously by the Board as distribution assets.

As shown in Figure 1-1 above, ERHDC is a wholly-owned subsidiary of NBHHL.

The senior management team at NBHDL and ERHDC are currently the same.

5.2 Geographic territory served by each of the parties to the Proposed Amalgamation

The following statistics (aside from Service Area and Municipal Population) are obtained from the 2020 OEB Yearbook issued on September 10, 2021.[15] Service Area and Municipal Population statistics of NBHDL and ERHDC are obtained from 2016 Census data and information from Town of Massey website.[16]

NBHDL Service Area:

Community served:	City of North Bay
Total service area:	330 sq. km
Rural service area:	279 sq. km
Distribution type:	Electricity distribution
Residential Customers Served:	21,365

[15] Ontario Energy Board Yearbook of Electricity Distributors 2020/21, Available Online: https://www.oeb.ca/oeb/_Documents/RRR/2020_Yearbook_of_Electricity_Distributors.pdf (Last Accessed: October 12, 2021).
[16] The Town of Massey, Available Online: http://www.masseyontheriver.com/massey.html (Last Accessed: November 11, 2021).

Service area population:	approx. 51,553
Municipal population:	approx. 51,553

ERHDC Service Area:

Community served:	Town of Espanola and Township of Sables-Spanish Rivers
Total service area:	83 sq. km
Rural service area:	26 sq. km
Distribution type:	Electricity distribution
Residential Customers Served:	2,918
Service area population:	approx. 6,600
Municipal population:	approx. 6,600

Both NBHDL and ERHDC are bounded by Hydro One Networks Inc. on all service territory boundaries.

Hydro One Networks Inc.
483 Bay St.
Toronto, ON M5G 1P5
Direct Line: 416-345-5000
Website: wwww.HydroOne.com

The service area boundaries of NBHDL and ERHDC are not contiguous and are approximately 175 km apart.

Though Espanola is two (2) hours from the City of North Bay, the two utilities operate in very similar geographic territories within Northern Ontario, and many of the service area characteristics are also comparable.

For example, the rural service territory in both communities exceeds 75% of overall territory; 76% of ERHDC’s territory and 85% of NBHDL’s territory; and both utilities operate a primarily overhead system; 89% for ERHDC and 86% for NBHDL.

Table 5-1 below provides a summary of the service territory characteristics between ERHDC and NBHDL showing the number of square kilometres for rural and urban service areas as well as kilometres of line that are overhead and underground.

Table 5-1: Service Territory Characteristics

Characteristics	**ERHDC**		**NBHDL**	
Rural Service Area (sq km)	83	76%	279	85%
Urban Service Area (sq km)	26	24%	51	15%
Total Service Area (sq km)	109		330	
# of Customers / sq km	30.5		73.6	
Overhead Circuit km of Line	90	89%	493	86%
Underground Circuit km of Line	11	11%	81	14%
Total Circuit km of Line	101		574	
# of Customers / km of Line	33.0		42.3	

Maps of the NBHDL and ERHDC service areas, and the relative distance between the two, are attached hereto at Appendix C.

5.3 Proposed geographic service area after completion of the Proposed Amalgamation

Upon completion of this Proposed Amalgamation and the approval of this MAADs application, the service areas of ERHDC and NBHDL will be combined to be served by a single merged utility.

5.4 Description of customers, including number of customers in each class, served by each of the parties to the Proposed Amalgamation

NBHDL and ERHDC are comparable both in the types of customer classes served by each utility and the service territories in which each operate with similar characteristics and terrain.

Table 5-2 below provides the number of customers/connections by rate class for 2020. Excluding the classes that are based on connections, both LDCs have a customer base that is primarily driven by the residential class (88%), followed by smaller commercial businesses that make up the general service < 50 kW class (11%). Only 1% of the customer base is made of up larger customers in the general service >= 50 kW class for both LDCs.

Currently, neither NBHDL nor ERHDC have any customers classified as large user or sub-transmission customers.

Table 5-2: 2020 Customers / Connections

Customer Rate Classifications	2020 - Number of Customers / Connections		2020 - % of Customers	
	ERHDC	**NBHDL**	**ERHDC**	**NBHDL**
Customers:				
Residential	2,918	21,365	88%	88%
General Service < 50 kW	381	2,660	11%	11%
General Service >= 50 kW	29	265	1%	1%
Total Customers	***3,328***	***24,290***	***100%***	***100%***
Connections:				
Street Lights	1,072	5,424		
Sentinel Lights	24	416		
Unmetered Scattered Load	21	9		
Total Connections	***1,117***	***5,849***		
Total	**4,445**	**30,139**		

Both communities have experienced little to no growth over the last several years, as shown in Table 5-3 below that compares 2020 customer counts against 2013 for both ERHDC and NBHDL.

Table 5-3: 2020 vs. 2013 Customers

Customer Rate Classifications	ERHDC				NBHDL			
	2020	**2013**	**(#)**	**(%)**	**2020**	**2013**	**(#)**	**(%)**
Customers:								
Residential	2,918	2,866	52	2%	21,365	21,064	301	1%
General Service < 50 kW	381	406	(25)	-6%	2,660	2,654	6	0%
General Service >= 50 kW	29	29	-	0%	265	255	10	4%
Total Customers	**3,328**	**3,301**	**27**		**24,290**	**23,973**	**317**	
% Change - 2020 vs. 2013			***1%***				***1%***	

5.5 Current net metering thresholds of NBHDL and ERHDC

Drawing from OEB's 2020 Yearbook data, the following table shows the calculated net metering thresholds for both ERHDC and NBHDL, calculated as 1% of the maximum peak demand (kW) averaged over a 3 year period[17] between 2018-2020.

Table 5-4: Net Metering Thresholds

Distributor	**kW Threshold**
ERHDC	155
NBHDL	973
Total	**1,127**

5.6 Final legal document to be used to implement the Proposed Amalgamation

As mentioned above, no formal amalgamation agreement is required to implement the Proposed Amalgamation. Pursuant to section 177(2) of the OBCA, two or more wholly-owned subsidiary corporations of the same holding body corporate may amalgamate and continue as one corporation without complying with section 175 and 176 provided that the amalgamation is approved by a resolution of the directors of each amalgamating corporation and the resolution requirements are met.

Copies of appropriate resolutions by parties approving the Proposed Amalgamation are attached in Appendix B, and include:

- Resolutions of the Board of Directors of NBHDL dated September 22, 2021;
- Resolutions of the Board of Directors of NBHHL dated September 21, 2021; and
- Resolutions of the Board of Directors of ERHDC dated September 2, 2021.

[17] Ontario Energy Board, Distribution System Code, Last revised on March 1, 2020 (Originally Issued on July 14, 2000), Section 6.7.2.

6. Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

6.1 Impact with respect to prices

NBHDL and ERHDC will be amalgamated into a single distribution company, New NBHDL, as a result of this Proposed Amalgamation.

The Proposed Amalgamation involves two Northern Ontario utilities that operate very similar service territories and provides an opportunity for a smaller utility to draw upon the corporate structure and resources including in-house expertise of a near-by, larger northern LDC.

Following the Proposed Amalgamation, the Applicants forecast OM&A synergies will range between $657,000 to $686,000 per year, as shown in Table 6-1 below, which shows the forecasted synergies.

In light of the unique circumstances associated with this two-phase transaction, and in consideration of independent rebasings of both NBHDL and ERHDC prior to the Proposed Amalgamation, NBHDL is willing to forego its right under the Handbook to defer rebasing for up-to 10 years following the Proposed Amalgamation.

Specifically, NBHDL would only defer rebasing for five (5) years following the Proposed Amalgamation. This is consistent with the evidence in the Phase 1 transaction.[18] This ensures that ratepayers will gain the benefits associated with this amalgamation by no later than 2027.

Table 6-1 is a cost structure analysis showing the forecasted synergies for ERHDC and NBHDL from 2021 to 2027. The source of the "Status Quo – OM&A/Customer" in Table 6-1 below is based on the OM&A in the OEB-approved Revenue Requirement Workforms for ERHDC[19] and NBHDL[20] in their respective COS proceedings. The Applicants then assumed, for the purposes

[18] Phase 1 Application at pages 14, 25 and 37.
[19] EB-2020-0020 – Revenue Requirement Workform dated May 10, 2021 at Tab 5.
[20] EB-2020-0043 – Revenue Requirement Workform dated September 15, 2021 at Tab 5.

of forecast only, an annual OM&A inflation rate at 1.9% until 2027.[21] The Applicants then divided the result by the number of customers from the OEB's 2020 Yearbook. The number of customers are assumed to be approximately the same in 2027 given that both communities have experienced little to no growth over the last several years, as shown in Table 5-3 above.

Table 6-1: Forecasted Synergies

OM&A Costs ('000)	**2021**	**2022**	**2023***	**2024**	**2025**	**2026**	**2027**
ERHDL	1,573	1,603	1,634	1,665	1,696	1,729	1,762
NBHDL	7,816	7,912	8,059	8,212	8,368	8,527	8,689
Status Quo OM&A Costs	9,389	9,515	9,693	9,877	10,065	10,256	10,451
Synergies	75	-572	-657	-667	-676	-686	-686
Proposed OM&A Costs	9,464	8,943	9,036	9,210	9,388	9,570	9,765
**Amalgamation = partial year 2022 ~ full year 2023*							
Efficiency Forecast							
ERHDL Customers	3,328	3,328	3,328	3,328	3,328	3,328	3,328
OM&A/customer	$472.79	$481.77	$490.92	$500.25	$509.75	$519.44	**$529.31**
NBHDL Customers	24,290	24,290	24,290	24,290	24,290	24,290	24,290
OM&A/customer	$321.78	$325.72	$331.78	$338.09	$344.51	$351.05	**$357.72**
New NBHDL Customers							27,618
OM&A/customer							**$353.57**

	2020 Customers	**Customer Proration**	**Proposed OM&A Cost**	**Proposed OM&A Cost/ Customer**	**Status Quo - OM&A / Customer**	**Variance ($/Customer)**	**Variance (%)**
ERHDL	3,328	12%	1,176,668	$353.57	$529.31	**($175.74)**	-33%
NBHDL	24,290	88%	8,588,124	$353.57	$357.72	**($4.16)**	-1%
	27,618	100%	**9,764,793**				

[21] The Applicants expect that actual OM&A costs will vary over time. However, this inflation assumption is the best available information at the time of filing this Application.

The proposed cost structure for combining ERHDC and NBHDL is shown in Table 6-1 above. A downward movement of ERHDC's underlying cost structure is expected as a result of amalgamation together with the expiry of the PUC Services Agreement, compared to the status quo. These synergies would not be possible if ERHDC continued operating at status quo. As shown in Table 6-1, the total OM&A costs to serve ERHDC and NBHDL customers will reduce from $9,693 in the status quo scenario to $9,036 in 2023 if the OEB approves the amalgamation.

One of the reasons that synergies will be made possible is because of NBHDL's ability to assume the functions under the PUC Services Agreement without any incremental cost to customers. This will occur subsequent to the expiration of the PUC Services Agreement on February 28, 2022. ERHDC customers are forecasted to see a significant reduction in OM&A per customer in 2027, from $529 to $354. In addition, NBHDL customers are forecasted to see a modest reduction in OM&A per customer in 2027 from $358 to $354, arising principally from NBHDL's ability to spread its existing overhead costs over a larger number of customers. Therefore, both ERHDC and NBHDL customers will benefit from the amalgamation.

While the termination of the PUC contract represents a significant portion of the synergies expected, it is important to note that there are further synergies that will arise from the amalgamation itself that represent approximately 30% of the forecasted synergies. These benefits include eliminating costs where duplication exists in both businesses, typical of the centralization of back-office functions, such as audits, board of directors, membership and association fees, and software costs.

Underlying cost structures are forecasted to be lower than they would have been for ERHDC customers, and no higher than they would otherwise have been for NBHDL customers.

In its 2021 Cost of Service Application, ERHDC proposed filing a one-year DSP that will only cover the 2021 forward test year, rather than a full five-year DSP given that NBHDL will completely replace ERHDC's distribution system planning function with existing NBHDL resources after the merger. The OEB accepted this proposal.

It is anticipated that there will be substantial infrastructure requirements of ERHDC over the next 10 years, which will be primarily related to substation rebuilds. NBHDL has significant experience constructing substations. NBHDL designs have been adopted by other small to medium sized LDCs across Ontario, including a station rebuild at ERHDC. It is expected that ERHDC will benefit significantly from this expertise in the design, planning and execution of future planned rebuilds. In addition, NBHDL's design and engineering is in-house and the Engineering and Operations departments work hand in hand in the design, planning, estimating, management and execution of capital projects. In doing so, the use of consultants and 3rd parties for design will be curtailed if not fully eliminated.

With two – five year DSP's approved and accepted by the OEB through previous rate applications NBHDL will provide invaluable experience in crafting the next many years of distribution system planning at ERHDC. The sharing of resources, fleet, and equipment between the two operations centres will be beneficial over the course of time in situations such as large projects, unexpected equipment breakdown and/or unexpected absence by eliminated or reducing the need for external aid and additional cost in said situations. The use of new material or innovative products utilized in the construction of capital projects trialed by NBHDL that may produce cost savings, productivity improvements or enhance safety will be pushed to ERHDC for use. After amalgamation, the teams will strive to unlock any other potential synergies and further operational efficiencies through the sharing of processes, work methods, and resource expertise and experience.

After the PUC Services Agreement ends, significant OM&A cost savings and efficiency gains can be made through the consolidation of administrative practices and economies of scale. This includes the consolidation of management, billing, customer service, finance and regulatory functions.

Relative to the status quo the proposed transaction is expected to deliver sustainable reductions to the underlying cost structure of New NBHDL customers.

Incremental one-time transaction and transition costs related to the Proposed Amalgamation are approximately $300,000. These costs are not, and will not, be recovered from ratepayers through underlying OM&A cost structures, but will be funded through company residual earnings. Transaction costs of $85,000 are related to the MAADs application proceeding and the amalgamation requirement. Incremental transition costs of $215,000 incorporate the estimated costs of transitioning all ERHDC services to NBHDL including billing, accounting, IT, and customer communication. These costs include both internal and external one-time costs.

6.2 Impact with respect to the adequacy, reliability and quality of electricity service

An objective of NBHDL is that of a Northern Ontario LDC that provides effective and efficient service with a focus on the communities that rely on it.

NBHDL believes strongly in having a local physical presence no different than what ERHDC customers experience today. Service levels and quality standards will continue after the transaction and post-amalgamation. NBHDL and ERHDC are committed to maintaining the adequacy of electricity service for its customers and in order to continue operating with the service that customers have come to expect, it is proposed that the existing service center will continue to operate in Espanola.

Front line operations staff that currently respond to outages and power quality issues are expected to continue to serve the same communities. The Applicants anticipate that response times will not decline. It is the intention of the Applicants to maintain the service levels of both LDCs through the merging of technologies, system control, adoption of best work practices, etc.

Historically NBHDL and ERHDC have maintained strong reliability measures in both System Average Interruption Duration Index ("**SAIDI**") and System Average Interruption Frequency Index ("**SAIFI**") metrics. SAIFI and SAIDI results for the year ending 2020 indicate that both LDCs have provided their customers with excellent reliability and both utilities have expertise in the elements and conditions which affect reliability in Northern Ontario. The five-year historical reliability metrics for NBHDL and ERHDC are provided in Table 6-3 below.

Table 6-3: Historic Service Quality Indicators of ERHDC and NBHDL

Service Quality Indicators					
	2020	**2019**	**2018**	**2017**	**2016**
SAIDI:					
ERHDC	0.21	0.35	0.16	0.35	0.55
NBHDL	1.08	1.16	1.95	1.11	2.29
SAIFI:					
ERHDC	0.06	0.17	0.06	1.1	0.10
NBHDL	0.78	1.35	1.40	0.94	1.98

There will be a large benefit to ERHDC customers arising from the amalgamation in the form of technology enhancements in the ERHDC service territory that would otherwise not be economical to implement.

These benefits include:

- The extension of NBHDL SCADA system to ERHDC;
- Visibility into HONI's grid control at interfacing transmission stations via the existing NBHDL ICCP link;
- Extension of NBHDL Geographic Information System (GIS) to include the ERHDC service area;
- Extension of the NBHDL customer website outage map to include the ERHDC service area;
- Extension of the NBHDL social media platforms (Twitter, Facebook) to include ERHDC to aid in the promotion of distributor activities, engagement of customers, and communication of outage information; and
- Implementation of a stable, secure information technology backbone, aligned with current cyber security regulatory requirements, with full remote support from NBHDL.

Of great value to ERHDC will be the access to fully resourced operations, engineering and customer service departments at NBHDL, providing a larger internal pool of resources to handle and improve all aspects of system adequacy, reliability and quality of electrical service. Of note, the ERHDC electrical system will be displayed, managed, and operated from the NBHDL Control Room, an element of operation that is currently lacking at ERHDC. This change will aid in the optimization of power distribution, the issuance of work, and work protection and improve the overall operation and safety of the grid in normal and outage event situations. The larger resource pool will also aid in the ability for ERHDC to meet the requirements of an ever-changing industry and unlock the potential of technological advances and innovative projects to further promote stronger adequacy, reliability, and quality of electrical service.

The OEB states in the Handbook that its review of "no harm" in respect of the adequacy, reliability and quality of service will be informed by the distributors' metrics as filed with the OEB, and its annual scorecard performance. The 2020 scorecards of both ERHDC and NBHDL are provided in Appendix D. Both scorecards demonstrate extremely strong performance and trending in the areas of customer service and reliability and demonstrate a further alignment of objectives aimed at maintaining or improving service levels. The following highlights the Customer Focus statistics:[22]

[22] First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors. For NBHDL, First Contact Resolution is measured based on the number of customer concerns that are escalated formally to NBHDL's President or directly to the OEB. By contrast, ERHDC's First Contact Resolution was measured by tracking the number of electric related calls that were escalated to a Senior Customer Care Representative, Supervisor, or Manager. In 2017, ERH had 3,955 calls, of which, 16 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.60%.

1 **Table 6-4: Customer Focus Statistics**

CUSTOMER FOCUS												
YEAR	New Residential/Small Business Services Connected on Time (Target: 90%)		Scheduled Appointments Met on Time (Target: 90%)		Telephone Calls Answered on Time (Target: 65%)		First Contact Resolution		Billing Accuracy (Target: 98%)		Customer Satisfaction Survey Results	
	ERH	NBHDL	ERH	NBHDL	ERH	NBHDL	ERH	NBHDL	ERH	NBHDL	ERH	NBHDL
2013	94.70%	100.00%	95.40%	100.00%	74.80%	78.20%						93.3%
2014	100.00%	100.00%	100.00%	100.00%	77.30%	78.40%	100.00%	4	99.83%	99.92%		A
2015	100.00%	100.00%	100.00%	100.00%	76.10%	82.10%	99.80%	6	99.93%	99.88%	89.00%	A
2016	100.00%	100.00%	100.00%	99.90%	76.20%	83.60%	99.17%	14	99.95%	99.70%	87.00%	85.00%
2017	100.00%	100.00%	98.18%	100.00%	72.62%	86.56%	99.60%	6	99.95%	99.74%	87.00%	85.00%
2018	100.00%	100.00%	100.00%	100.00%	70.67%	91.13%	99.73%	4	99.89%	99.72%	87.00%	89.00%
2019	100.00%	100.00%	99.72%	100.00%	63.04%	95.65%	99.23%	3	99.98%	99.87%	91.00%	89.00%
2020	100.00%	100.00%	100.00%	100.00%	68.04%	82.23%	99.70%	2	99.94%	98.71%	91.00%	86.00%

Notably, prior to the proposed amalgamation, ERHDC's telephone calls answered on time has fallen below the industry target of 65% in 2019. New NBHDL will seek to make improvements to ERHDC's "Telephone Calls Answered On Time".

6.3 Describe how the distribution systems within the service areas will be operated, including whether the proposed transaction will cause a change of control

Change of Control

Following OEB's approval of the transaction, the distribution businesses of NBHDL and ERHDC will consolidate into a single distributor, referred to in this Application as New NBHDL. NBHHL and the City of North Bay are the sole owners of both NBHDL and ERHDC prior to the Proposed Amalgamation. These same entities will be the sole owners of New NBHDL. Therefore, there will be no change of control from a legal ownership perspective. There will be a change of operational control of ERHDC's distribution system due to the expiry of the PUC Services Agreement.

Distribution System Operations

Due to the distance between the two utilities and the importance of maintaining and/or enhancing current customer service levels, it is proposed that the current operation centres will be maintained in both service territories throughout the duration of this process. This will ensure the continuance of local focus to ensure strong community relationships and top tier customer service for both territories.

The following table depicts how distribution system operations will be managed:

<u>Table 6-5: Distribution System Operations Subsequent to Amalgamation</u>

Service Territory	Operations Centre	Management Services	Control
ERHDC	Current ERHDC Office	NBHDL	New NBHDL
NBHDL	Current NBHDL Office	NBHDL	New NBHDL

The main headquarters will be the current NBHDL office, located in North Bay, Ontario. Functions such as engineering, procurement, human resources, finance, regulatory, information technology, customer service and conservation will be administered and delivered from the North Bay location, with each location having Operations staffing similar to current resourcing levels.

The organization of New NBHDL's operational structure will be implemented in a way that ensures ERHDC leverages the centralized functions at NBHDL that make NBHDL an efficient, effective, and compliant LDC while still ensuring a local presence exists in both service territories. It is extremely important to provide the same level of local service the communities are accustomed to. The adoption and extension of NBHDL's processes and systems by ERHDC will provide an economical approach to unlocking opportunities and levels of service that would otherwise be cost prohibitive to consider, and will eliminate the need for the PUC Services Agreement currently in place.

Although the majority of the operational benefit of the acquisition flows to the customers of ERHDC, NBHDL looks forward to the collaboration and distribution operation experience it will gain through the retention of ERHDC staff and the formation of best operational practices through the creation of New NBHDL. This will be ever evolving and New NBHDL will continue to evaluate how to best engage resources and deliver service in a way to maximize benefits to customers in both service territories.

7. Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

7.1 Indicate the impact of proposed transaction on economic efficiency and cost effectiveness in the distribution of electricity; identifying the various aspects of utility operations where the applicant expects sustained operation efficiencies (both quantitative and qualitative).

There is significant potential for economic efficiencies and cost effectiveness that would arise from the amalgamation of NBHDL and ERHDC. Despite the distance in service territories and size, the similarities between NBHDL and ERHDC provide value for the customers of ERHDC. NBHDL is skilled at operating an overhead system in a primarily rural service territory, addressing the unique needs of the community and customers that this brings, and doing so in a cost-efficient manner. This management philosophy and operational expertise will be brought to ERHDC. Over the long-term horizon, this acquisition is anticipated to generate sustainable administrative cost savings as a result of centralizing back-office functions including management, billing, customer service, finance and regulatory functions. The acquisition will also provide ERHDC with the benefit of being a part of a larger strategic plan that focuses on driving the LDC forward. The core strengths of NBHDL in community building, reliability, safety, operations, customer service and solid financial performance will be leveraged by ERHDC through one integrated management team and board of directors. The anticipated savings will be passed on to customers through lower OM&A costs when New NBHDL prepares a full cost of service application in 2027.

The first step in addressing the immediate need for ERHDC to realign rates and deal with a declining ROE has been completed through ERHDC's filing of its cost of service application for 2021 rates. The Proposed Amalgamation will provide for sustainable cost reductions that benefit customers over the longer term without reducing the levels of customer service and reliability that ERHDC customers expect.

7.2 Identify all incremental costs of the proposed transaction and how these costs will be financed

Incremental one-time transaction and transition costs related to the Proposed Amalgamation are approximately $300,000. These costs are not, and will not, be recovered from ratepayers through underlying OM&A cost structures, but will be funded through company residual earnings. Transaction costs of $85,000 are related to the MAADs application proceeding and the amalgamation requirement. Incremental transition costs of $215,000 incorporate the estimated costs of transitioning all ERHDC services to NBHDL including billing, accounting, IT, and customer communication. These costs include both internal and external one-time costs.

Implementation/Integration Costs

The integration costs will be financed through the anticipated productivity savings expected from the transaction during the period after NBHDL and ERHDC amalgamate and through retained earnings. As always, there will be timing differences between expense outlays and their recovery.

OM&A incremental transitional costs are primarily related to:

- Transition planning and execution – third party and additional staff costs related to implementing the transition plan, including the costs related to the MAADs application;
- IT costs – costs associated with system integration and standardization;
- Communication costs – development and execution of customer and other stakeholder communications at various stages of transition; and
- Workforce training – costs associated with retraining employees on new systems, processes and policies.

7.3 Provide a valuation of assets or shares that will be transferred in the Proposed Amalgamation

The shares of ERHDC will be cancelled without repayment of capital in accordance with Section 177(2)(b)(i) of the OBCA.

The stated capital of the amalgamating subsidiary corporation whose shares are cancelled (i.e. ERHDC) will be added to the stated capital of the amalgamating subsidiary corporation whose shares are not cancelled (i.e. NBHDL). The stated capital of ERHDC is shown in the table below as agreed upon with NBHHL.

Table 7-1: ERHDC Share Capital

Share capital

		2020		2019
Authorized				
Unlimited number of common shares				
Issued				
100 common shares	$	100	$	100

7.4 Details as to why purchase price will not have an adverse effect on the financial viability of the acquiring utility

As mentioned above, the shares of ERHDC will be cancelled without repayment of capital and its stated capital will be added to the stated capital of NBHDL. As this is a horizontal amalgamation, there is no purchase price involved.

Both NBHDL and ERHDC have underwent full cost of service applications that address the distribution revenue requirements of the business. While this step was a critical first step to re-establishing ERHDC's financial viability, the Proposed Amalgamation addresses the broader context of ERHDC's current and future lending requirements in order to continue investing and rehabilitating its distribution system, including the need for three distribution substations rehabilitations over the next 10 years. ERHDC relies heavily on NBHDL to support external financing requirements through guarantees on all existing debt with TD and Infrastructure Ontario, including acquisition lending that was 100% financed upon completion of the Phase 1 application, and annual borrowing for capital infrastructure requirements. While guarantees are in place until amalgamation, with no specific date referenced, negotiations with external lenders were only able to secure three-year covenant waivers through to January 1, 2023. It is the strength of NBHDL's balance sheet that lends assurance to the lender, including the willingness to provide covenant waivers, however these cannot go on into perpetuity. The Proposed Amalgamation enables

ERHDC to address current and future capital infrastructure financing needs, remove the reliance on NBHDL, and takes advantage of favourable lending options that are associated with NBHDL that would otherwise be difficult based on ERHDC's size.

Once amalgamated, New NBHDL will continue to have strong liquidity and debt service ratios as well as more optimal debt to equity ratios with financial capacity for necessary borrowing.

7.5 Details of the financing of the proposed transaction

There is no financing for this proposed transaction as it is a horizontal amalgamation.

7.6 Financial statements

Appendix E to this Application contains ERHDC and NBHDL's audited annual financial statements for the years 2019 and 2020.

7.7 Pro forma financial statements

Appendix F to this Application contains the pro forma financial statements for New NBHDL for the first full year following the Proposed Amalgamation.

8. Rate Considerations for Consolidation Applications

8.1 Rebasing Deferral Period

The Applicants propose a rebasing deferral period of five (5) years from the date of closing of the Proposed Amalgamation. The rates in each of the two service territories will continue to be set by the OEB's Price Cap IR during the rebasing deferral period with the intention of filing a cost of service application in 2027 with a plan to propose rate harmonization.

8.2 Earnings Sharing Mechanism

As described in the Reply Submissions in the Phase 1 Application, the Applicants proposed to include an ESM that would share overearnings 300 basis points above the OEB-approved ROE on a 50:50 basis with ratepayers beginning in year six following the closing of the Phase 1 transaction.

In accordance with the MAADs Decision, by way of correspondence, NBEAI notified the OEB of the closing of the Phase 1 transaction on October 1, 2019.[23] Therefore, year six following the closing would be starting October 1, 2025, which is when the ESM is proposed to commence.

The Applicants submit that this approach to ESM is consistent with the OEB's policy as outlined in *Report of the Board – Rate-making Associated with Distributor Consolidation* issued July 23, 2007 and updated March 26, 2015, in consideration of the unique circumstances of this two-phase transaction.

9. Other Related Matters

9.1 Implementation of new or the extension of existing rate riders

Each of NBHDL and ERHDC have rate orders that contains a number of rate riders established in order to dispose of balances in specified deferral and variance accounts. The rate riders will expire on dates determined in the Order of the OEB by which the riders were established. Please see the Tariff of Rates and Charges for ERHDC and NBHDL attached as Appendix G for the 2021 OEB-approved rate riders for ERHDC and NBHDL respectively.

9.2 Transfer of rate order and licence / Licence amendment and cancellation

The Applicants are requesting that the rate orders of ERHDC be transferred to NBHDL following the completion of the amalgamation. As mentioned, the Applicants are seeking approval for an order to amend NBHDL's distribution licence (ED-2003-0024) pursuant to section 74 of the OEB Act to include ERHDC's service territory, to be effective on the completion of the amalgamation

[23] EB-2019-0015 – Letter from NBEAI to OEB Re: Securities Purchase Agreement dated October 12, 2018 between The Corporation of the Town of Espanola, The Corporation of the Township of Sables-Spanish Rivers, North Bay Hydro Holdings Ltd. and North Bay (Espanola) Acquisition Inc. dated October 1, 2019.

and to be followed immediately by the cancellation of the distribution licence of ERHDC (ED-2002-0502) pursuant to section 77(5) of the OEB Act.

9.3 Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB

The Applicants request the OEB's approval to continue to track costs in the deferral and variance accounts currently approved by the OEB for all Ontario LDC's as well as for each of NBHDL and ERHDC.

9.4 Approval to use different accounting standards for financial reporting following the closing of the proposed transaction

The Applicants do not propose the use of any different accounting standards. ERHDC and NBHDL have transitioned to International Financial Reporting Standards ("**IFRS**") for financial accounting purposes and New NBHDL will also be using IFRS.

As mentioned in Section 1.2 above, ERHDC completed an analysis on the differences in accounting policies between ERHDC and NBHDL. The parties to the Settlement Proposal of the ERHDC COS agreed that nothing further is required as a result of this analysis on accounting policies.[24] The Settlement Proposal was accepted by the OEB in the ERHDC COS Decision.[25]

[24] ERHDC COS Decision, Schedule B, June 10, 2021 at page 42.
[25] ERHDC COS Decision at page 1.

1 **Appendix A**

2 **Mapping of Application to filing requirements**

	Filing Requirements	**Reference**
2.1 The Index	Index	
2.2 The Application		
2.2.1 Administrative		
	Certification of Evidence	Certificate of Evidence
	Legal name of the applicant	Section 1
	Details of the authorized representative of the applicant, including the name, phone and fax numbers, and email and delivery addresses	Section 4
	Legal name of the other party or parties to the transaction, if not an applicant	Section 4
	Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses	Section 4
	Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants	Section 1 and 2
2.2.2 Description of the Business of the Parties to the Transaction		
	Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity.	Section 5
	Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or if not the relative distance between service boundaries.	Section 5
	Describe the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.	Section 5
	Describe the proposed geographic service area of each of the parties after completion of the proposed transaction.	Section 5
	Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.	Section 1.2
	If the proposed transaction involves the consolidation of two or more distributors, please indicate the current net metering thresholds of the utilities involved in the proposed transaction.	Section 5.5

2.2.3 Description of the Proposed Transaction		
	Provide a detailed description of the proposed transaction.	Section 1.3
	Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the *Ontario Energy Board Act, 1998*.	Section 2
	Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.	Section 1.2
	Provide all final legal documents to be used to implement the proposed transaction.	Section 5.6
	Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction.	Section 5.6, Appendix B
2.2.4 Impact of the Proposed Transaction		
Objective 1 - Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service		
	Indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.	Section 6.1 and 6.2
	Provide a year over year comparative cost structure analysis for the proposed transaction, comparing the costs of the utilities post transaction and in the absence of the transaction.	Section 6.1, Table 6-1
	Provide a comparison of the OM&A cost per customer per year between the consolidating distributors.	Section 6.1, Table 6-1
	Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.	Section 6.3
	Describe how the distribution or transmission systems within the service areas will be operated.	Section 6.3
Objective 2 - Promote Economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry		
	Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity); identifying the various aspect of utility operations where the applicant expects sustained operation efficiencies (both quantitative and qualitative).	Section 7.1

	Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental merged costs (e.g. employee severances), and incremental on-going costs (e g purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.	Section 7.2
	Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.	Section 7.3, Table 7-1
	If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.	Section 7.4
	Provide details of the financing of the proposed transaction.	Section 7.5
	Provide financial statements (including balance sheet. income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years	Section 7.6, Appendix E
	Provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction	Section 7.7, Appendix F
2.2.5 Rate considerations for consolidation applications		
	Indicate a specific deferred rate rebasing period that has been chosen	Section 8.1
	For deferred rebasing periods greater than five years, confirm that the ESM will be as required by the 2015 Report and the Handbook	Section 8.2
	If the applicants proposed ESM a different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate the benefit to the customers of the acquired distributor	Section 8.2
2.2.6 Other Related Matters		
	Approval to continue with existing rate riders	Section 9.1, Appendix G
	Transfer of rate order and licence	Section 9.2
	Licence amendment and cancellation	Section 9.2
	Approval to continue to track costs to the deferral and variance accounts currently approved by the OEB	Section 9.3
	Confirmation re no change in accounting standards for financial reporting following the closing of the proposed transaction	Section 9.4

Appendix B

Board Resolution of NBHHL, NBHDL and ERHDC to Approve the Amalgamation

NORTH BAY HYDRO HOLDINGS LIMITED
(the "**Corporation**")

RESOLUTION OF THE DIRECTOR

Dated as of the 21st day of September, 2021.

RECITAL:

The Corporation holds all of the issued and outstanding shares in each of North Bay Hydro Distribution Limited. and Espanola Regional Hydro Distribution Corporation.

1. North Bay Hydro Distribution Limited. and Espanola Regional Hydro Distribution Corporation (the "**Subsidiaries**") have agreed to amalgamate and continue as one corporation under subsection 177(2) of the Business Corporation Act (Ontario) (the "Act"), upon approval by the Ontario Energy Board and at a date determined by any director or officer of the Subsidiaries;

RESOLVED THAT;

1. the amalgamation of North Bay Hydro Distribution Limited. and Espanola Regional Hydro Distribution Corporation under the name **North Bay Hydro Distribution Limited** be and the same is hereby authorized;

2. the current term of each member of the board of directors of North Bay Hydro Distribution Limited shall continue in accordance with the bylaws of North Bay Hydro Distribution Limited;

3. any director or officer of the Corporation is authorized and directed to do on behalf of the Corporation any and all acts and things and execute all documents as such director or officer considers necessary, desirable or useful to carry out and give effect to the amalgamation of the Corporation and the Subsidiaries and to this resolution.

4. these resolutions may be executed and delivered in any number of separate counterparts, each of which may be executed and delivered by facsimile transmission or electronically in PDF, DocuSign or other similar secure format. The Corporation shall be entitled to rely on delivery of such facsimile or electronically delivered counterparts and all such executed counterparts will be deemed an original and when taken together such counterparts will constitute one and the same document.

[signature page follows]

THIS resolution is consented to in writing by the undersigned.

Mac Bain	Johanne Brosseau
Earl Davison	Mark King
John G. Krieg	George Maroosis
Chris Mayne	Allan McDonald
Dave Mendicino	Scott Robertson
Bill Vrebosch	Tanya Vrebosch

Johanne Brosseau

124097800:v3

THIS resolution is consented to in writing by the undersigned.

Mac Bain	Johanne Brosseau
Earl Davison *Earl Davison*	Mark King
John G. Krieg	George Maroosis
Chris Mayne	Allan McDonald
Dave Mendicino	Scott Robertson
Bill Vrebosch	Tanya Vrebosch

124097800:v3

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Mac Bain	Johanne Brosseau
Earl Davison	Mark King
John G. Krieg	George Maroosis
Chris Mayne	Allan McDonald
Dave Mendicino	Scott Robertson
Bill Vrebosch	Tanya Vrebosch

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124097800:v3

THIS resolution is consented to in writing by the undersigned.

Mac Bain

Johanne Brosseau

Earl Davison

Mark King

John G. Krieg

George Maroosis

Chris Mayne

Chris Mayne

Allan McDonald

Dave Mendicino

Scott Robertson

Bill Vrebosch

Tanya Vrebosch

124097800:v3

NORTH BAY HYDRO DISTRIBUTION LIMITED
(the "**Corporation**")
RESOLUTION OF THE DIRECTOR

Resolution No. 21/27 Dated as of the 22 day of September, 2021

RECITALS:

A. The Corporation and Espanola Regional Hydro Distribution Corporation (the "Secondary Corporation") are wholly-owned subsidiaries of the same body corporate.

B. The Corporation wishes to amalgamate with the Secondary Corporation under the *Business Corporations Act* (Ontario) (the "Act").

RESOLVED that:

1. the Corporation amalgamate with the Secondary Corporation and continue as one corporation (the "Amalgamated Corporation") under subsection 177(2) of the Act, upon approval by the Ontario Energy Board and at a date as may be determined by any director or officer of the Corporation;

2. except as may be prescribed, the articles of amalgamation of the Amalgamated Corporation be the same as the articles of the Corporation;

3. the by-laws of the Amalgamated Corporation be the same as the by-laws of the Corporation;

4. on the issuance of a Certificate of Amalgamation under subsection 178(4) of the Act:

    (a) all shares of the Secondary Corporation be cancelled without any repayment of capital; and

    (b) the stated capital of the Secondary Corporation be added to the stated capital of the Corporation; and

5. any director or officer of the Corporation is authorized and directed to do on behalf of the Corporation any and all acts and things and execute all documents as such director or officer considers necessary, desirable or useful to carry out and give effect to the amalgamation of the Corporation and the Secondary Corporation and to this resolution.

6 these resolutions may be executed and delivered in any number of separate counterparts, each of which may be executed and delivered by facsimile transmission or electronically in PDF, DocuSign or other similar secure format. The Corporation shall be entitled to rely on delivery of such facsimile or electronically delivered counterparts and all such executed counterparts will be deemed an original and when taken together such counterparts will constitute one and the same document.

[signature page follows]

THIS resolution is consented to in writing by the undersigned.

Charles Gagnon

Christine Haas

John G. Krieg

Christopher Winrow

David Wolfe

124097984:v1

ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION
(the "**Corporation**")

RESOLUTION OF THE DIRECTORS

Resolution No. 21/16 Dated as of the 2 day of September, 2021

RECITALS:

A. The Corporation and North Bay Hydro Distribution Limited (the "Primary Corporation") are wholly-owned subsidiaries of the same body corporate.

B. The Corporation wishes to amalgamate with the Primary Corporation under the *Business Corporations Act* (Ontario) (the "Act").

RESOLVED that:

1. the Corporation amalgamate with the Primary Corporation and continued as one corporation (the "Amalgamated Corporation") under subsection 177(2) of the Act, upon approval by the Ontario Energy Board and at a date determined by any director or officer of the Corporation;

2. except as may be prescribed, the articles of amalgamation of the Amalgamated Corporation be the same as the articles of the Primary Corporation;

3. the by-laws of the amalgamated Corporation be the same as the by-laws of the Primary Corporation;

4. on the issuance of a Certificate of Amalgamation under subsection 178(4) of the Act:

   (a) all shares of the Corporation be cancelled without any repayment of capital; and

   (b) the stated capital of Corporation be added to the stated capital of the Primary Corporation; and

5. any director or officer of the Corporation is authorized and directed to do on behalf of the Corporation any and all acts and things and execute all deeds and documents as such director or officer considers necessary, desirable or useful to carry out and give effect to the amalgamation of the Corporation and the Primary Corporation and to this resolution.

[signature page follows]

THIS resolution is consented to in writing by the undersigned.

John Krieg

David Wolfe

Christopher Winrow

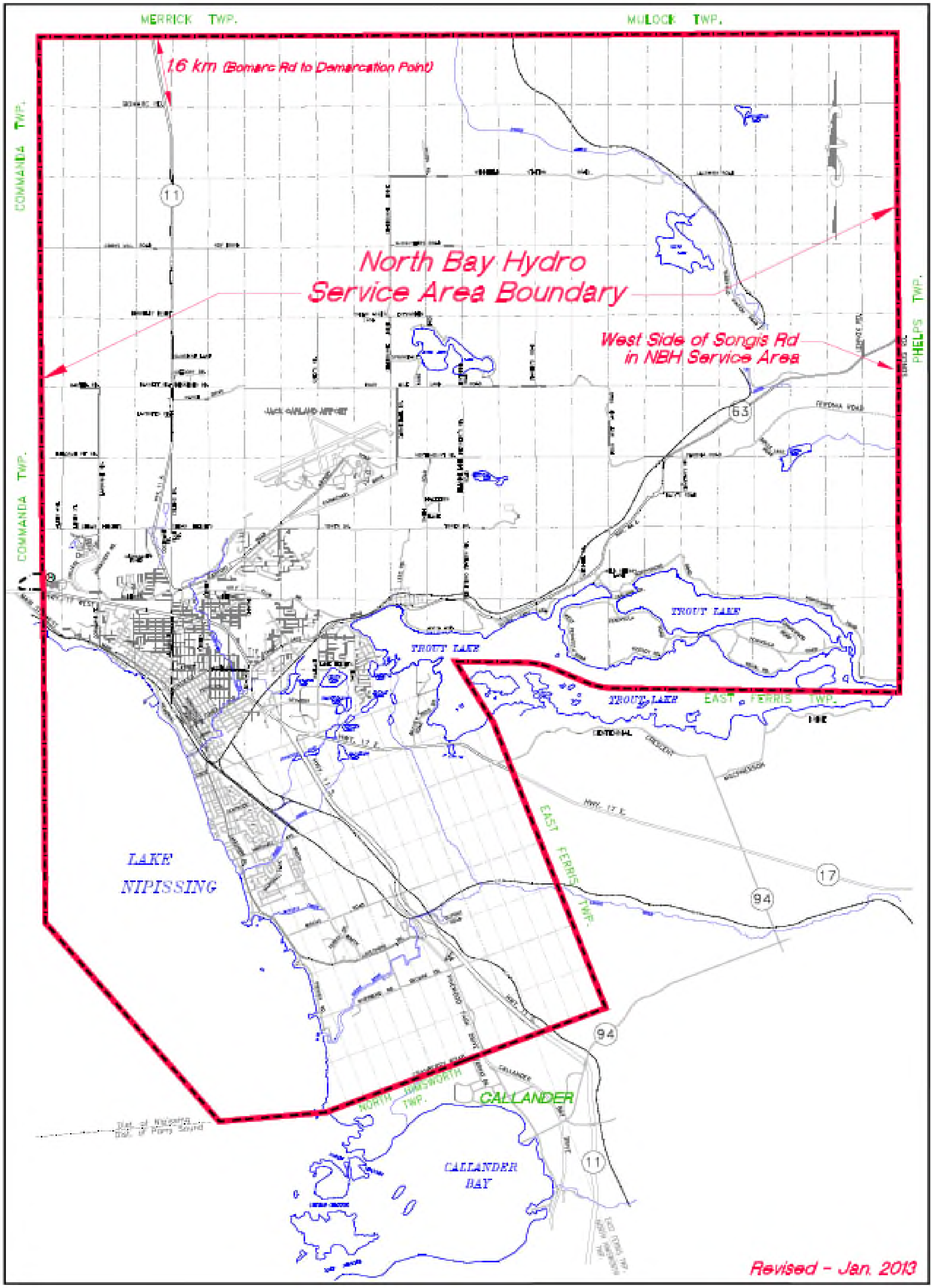
Stacie Fiddler

Derek Shogren

124098005:v2

Appendix C
NBHDL map of distribution service territory and distribution system

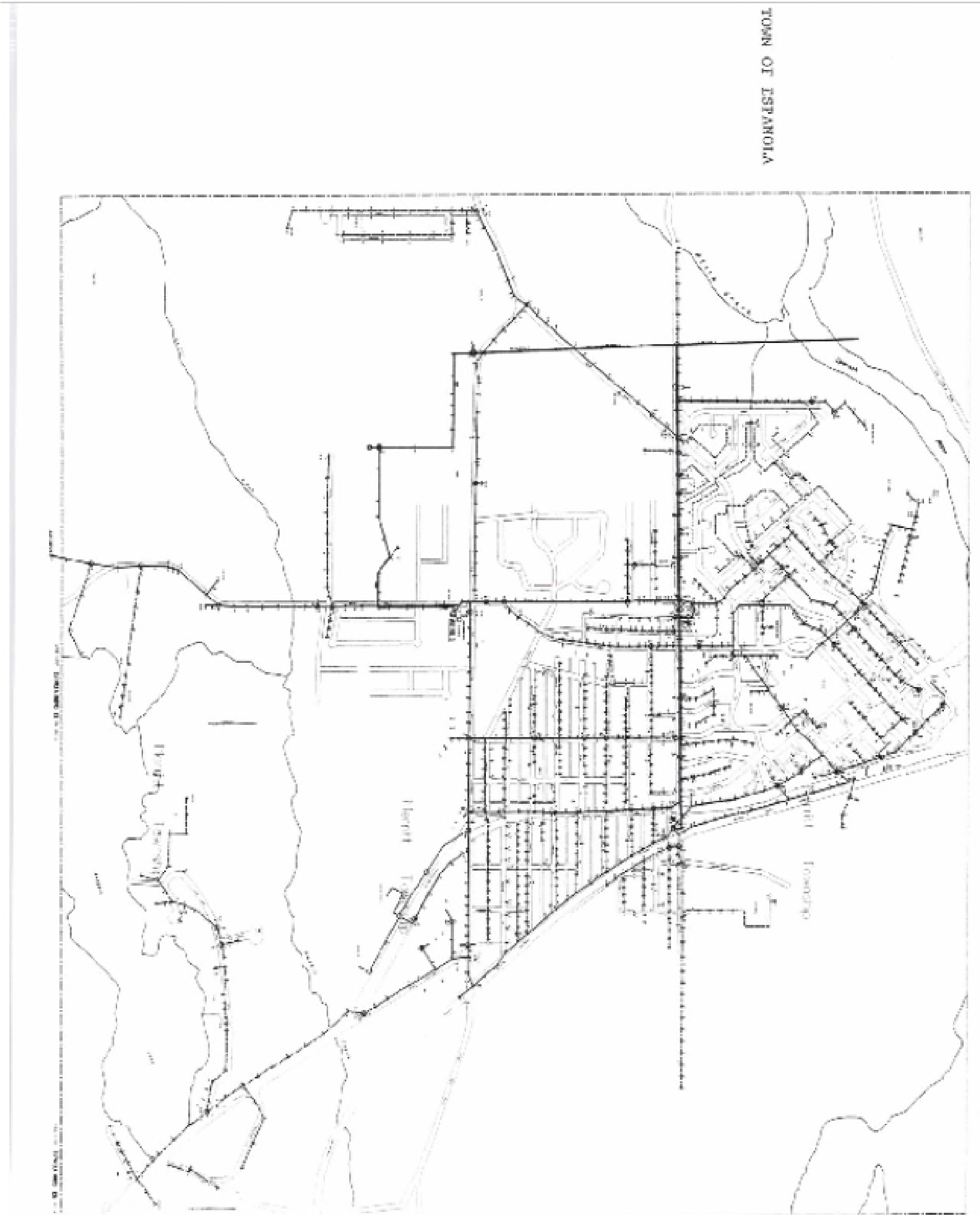
1

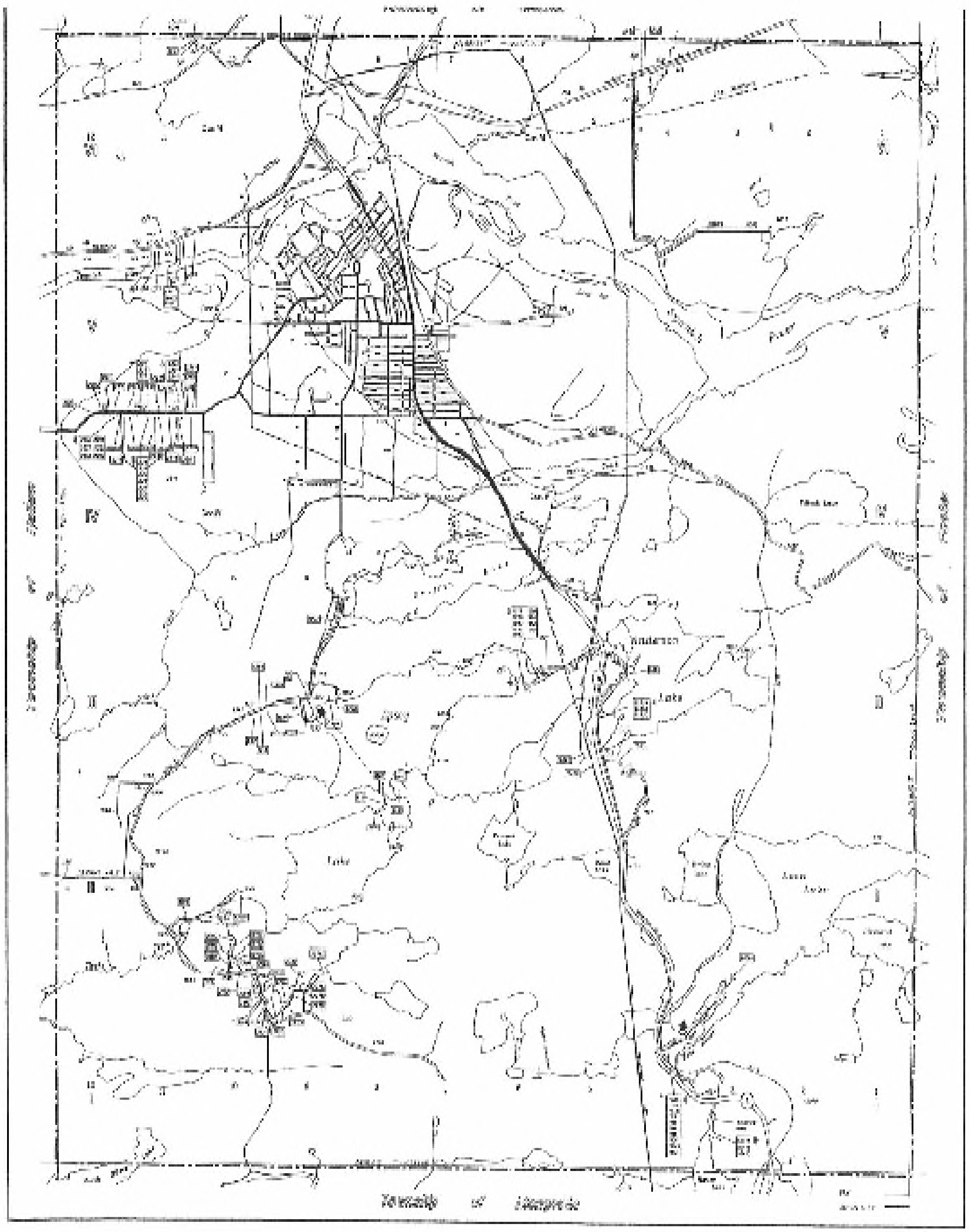

MERRICK TWP.
MULOCK TWP.
COMMANDA TWP.
PHELPS TWP.
16 km (Bomarc Rd to Demarcation Point)
North Bay Hydro
Service Area Boundary
West Side of Songis Rd
in NBH Service Area
TROUT LAKE
EAST FERRIS TWP.
LAKE
NIPISSING
NORTH HIMSWORTH TWP.
CALLANDER
CALLANDER
BAY
Revised - Jan. 2013

ERHDC map of distribution service territory and distribution system

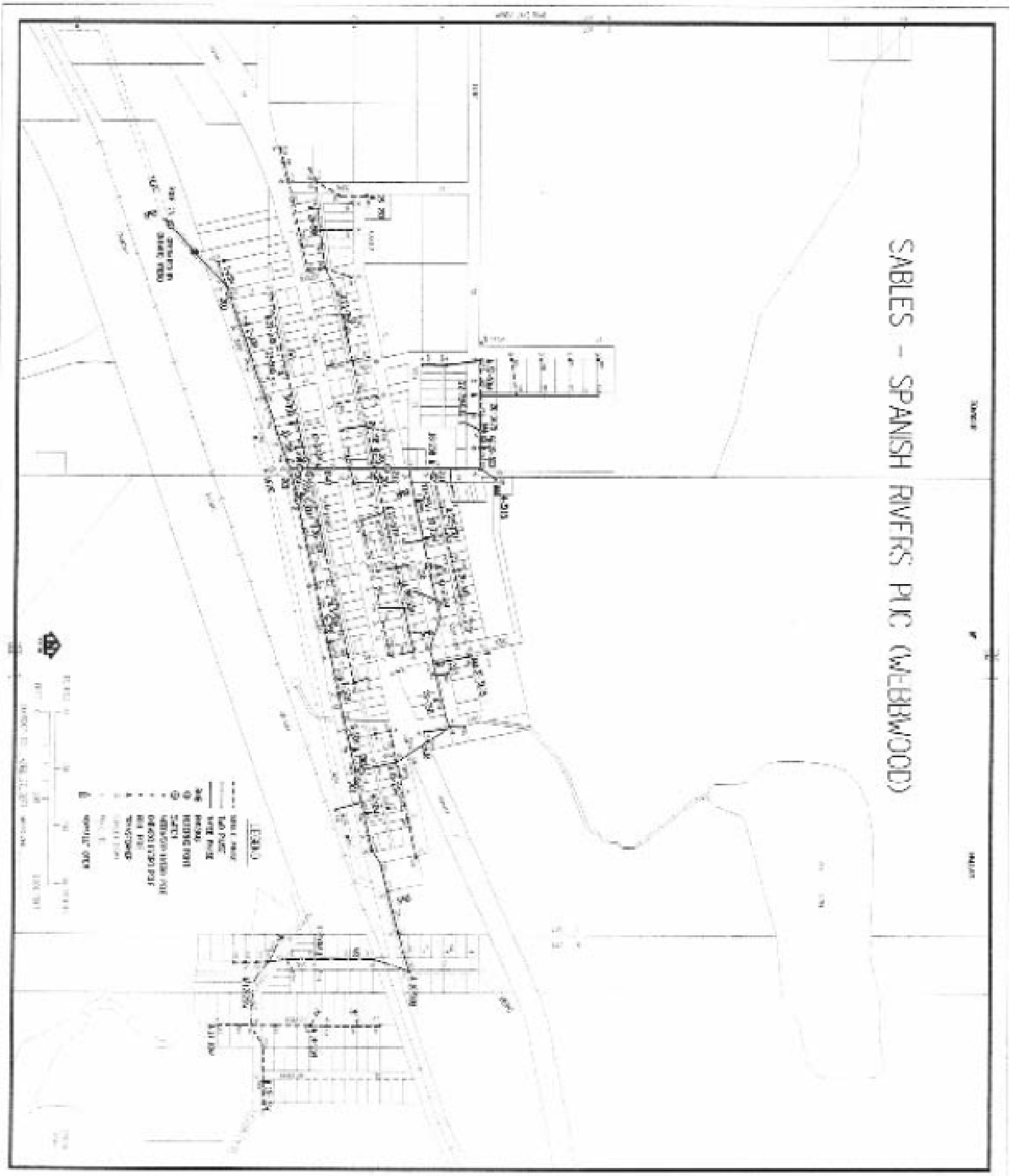
ERHDC services the electrical customers in the towns of Espanola, Massey, and Webwood as well as the surrounding rural area directly north and south of Espanola. The service area is depicted in **Figure 1**.

Figure 1: General ERHDC Service Area (From Left to Right: Massey, Webwood, Espanola)


TOWN OF ESPANOLA



MERRITT TOWNSHIP


SABLES - SPANISH RIVERS PUC (WEBBWOOD)


SABLES - SPANISH RIVER P.U.C. (MASSEY)

Map showing the relative distance between the service territories of NBHDL and ERHDC

Appendix D

2020 Scorecards of ERHDC and NBHDL

Scorecard - North Bay Hydro Distribution Limited

10/7/2021

Performance Outcomes	Performance Categories	Measures		2016	2017	2018	2019	2020	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		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		99.90%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Telephone Calls Answered On Time		83.60%	86.56%	91.13%	95.65%	82.23%		65.00%	
	Customer Satisfaction	First Contact Resolution		14	6	4	3	2			
		Billing Accuracy		99.70%	99.74%	99.72%	99.87%	98.71%		98.00%	
		Customer Satisfaction Survey Results		85%	85%	89%	89%	86%			
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%	81.00%	81.00%	81.00%			
		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]		2.29	1.11	1.95	1.16	1.08			1.52
		Average Number of Times that Power to a Customer is Interrupted [2]		1.98	0.94	1.40	1.35	0.78			1.31
	Asset Management	Distribution System Plan Implementation Progress		106%	118%	112%	119%	102%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$659	$672	$695	$732	$715			
		Total Cost per Km of Line [3]		$27,680	$28,233	$29,208	$30,928	$30,270			
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).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time					50.00%				
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	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)		2.09	1.92	1.84	1.69	1.58			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.95	1.01	1.00	1.03	1.14			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.30%	9.30%	9.30%	9.30%	9.30%			
			Achieved	9.01%	8.56%	10.17%	6.14%	4.64%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. 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.

Legend:

5-year trend: up | down | flat

Current year: target met | target not met

2020 Scorecard Management Discussion and Analysis ("2020 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2020 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2020 North Bay Hydro Distribution Ltd. ("NBHDL") once again met or exceeded all performance targets, continuing the 5-year trend that consistently shows an efficient, stable business meeting industry objectives.

- ✓ NBHDL owns, operates and manages the assets associated with the distribution of electricity to approximately 21,000 residential customers and 3,000 business customers operating in the city of North Bay.
- ✓ NBHDL continued its stable financial performance in 2020. Liquidity and leverage ratios were well within the target for a healthy, stable, financially viable company. While the achieved return-on-equity fell outside the deemed threshold, NBHDL was in the sixth year of a five-year rate cycle and has filed a Cost of Service (COS) application to address future capital infrastructure and operating requirements.
- ✓ In May 2020, NBHDL delayed its implementation of an approved rate increase. This was a temporary measure in response to the challenges being faced by NBHDL's customers and our community. Though NBHDL was given the option of recovering lost revenue at a later date, NBHDL elected not to, continuing in the spirit of rate relief for customers.
- ✓ NBHDL conducted its bi-annual customer satisfaction survey and continues to score well relative to provincial and national averages. In the aggregate, 91% of NBHDL customers are "satisfied" or "very satisfied" with the overall services we provide.
- ✓ The tree replacement initiative continues to be an encouragingly well-received program that results in an annual waiting list. In an effort to promote a Green Canopy and to give back to the community, NBHDL works with customers that are affected by NBHDL's vegetation management work. Due to COVID19 this program was temporarily halted. However, in its replacement NBHDL contributed to the City of North Bay's Clean, Green and Beautiful Campaign.
- ✓ NBHDL dedicated exhaustive resources into its updated Cost of Service Application that was filed in early 2021. This application will set the direction and scope for the next 5 years incorporating both the operational program and the capital delivery of NBHDL's investments in infrastructure renewal in the community.
- ✓ Our overall Scorecard performance is a result of NBHDL's continued investment in our infrastructure, our employees and in our response to customer needs.

The details provided in this report on service quality, customer satisfaction, safety, system reliability, asset management, cost control, CDM results, and financial ratios confirm NBHDL's continuing strong performance in 2020.

Service Quality

- ### New Residential/Small Business Services Connected on Time

In 2020, NBHDL connected 100% of 90 eligible low in-voltage residential and small business customers (59 in 2019, 47 in 2018) to its system within the five-day timeline prescribed by the OEB.

NBHDL has achieved 100% every year since 2009 and has done so through a continued commitment to customers and through adherence to workflow processes in place to meet the five-day window and to satisfy customer needs and expectations.

- ### Scheduled Appointments Met On Time

Approximately 4,000 appointments were scheduled with customers in 2020 for various activities including, but not limited to, work requested by customers, conservation and demand management initiatives, providing underground locate services, meter access and investigation when requested by customers. NBHDL also meets with customers regarding the vegetation management program that includes not only discussing the program itself, but addressing customer concerns and questions and obtaining the proper permissions for tree removal or trimming. NBHDL met all of these appointments on time, exceeding the industry target of 90%. NBHDL strives to maintain this high standard and has maintained a 99.9% average since 2009.

NBHDL maintains routine appointment scheduling for different activities (ex; service spots are completed every Thursday) and strives to meet appointments on time at all times. If the appointment is initiated by NBHDL, customers are contacted and scheduled at a time that best meets their schedule. An automated system handles underground locate requests which flow through Ontario One Call; once a customer calls into Ontario One Call an email is sent to NBHDL and a work order is automatically created and sent to service providers in the field. Field staff then schedule the work within a 5-day window. This automation has created a very efficient process for customers. Like many utilities NBHDL completes this program using experienced external contractors. This creates an efficient and cost-effective process to respond to customer requests.

- ### Telephone Calls Answered On Time

In 2020 Customer Accounts and Billing Specialists ("CABS") handled approximately 19,000 in-coming calls from customers; over 82% of those calls were answered in 30 seconds or less. This result exceeds the OEB mandated 65% target for timely call response. While this statistic is down compared to historical periods, NBHDL found that as a result of COVID protocols and the temporary closure of walk-in service, our staff spent more time on each call assisting customers during such a unique time. Staff provided necessary information on price changes, support programs, and worked with customers one on one to address their individual circumstances. Call duration naturally increases as a direct result of NBHDL's commitment to work with customers during the pandemic, but the result was a reduction in pick-up time on an initial call. Despite this, NBHDL is proud to still have performed well above the industry target.

NBHDL's Customer Service department is centralized to handle all inquiries; customers can call and speak with a representative that is able to handle all types of inquiries or concerns eliminating the need to transfer customers to different individuals or departments – a one-stop shop. It is important to note that, though not a statistic the OEB measures, CABs handled approximately 6,700 outbound calls in 2020.

Customer Satisfaction

With the exception of Billing Accuracy, specific customer satisfaction measurements have not been defined across the industry. The OEB has instructed utilities to review and develop measurements in these areas and begin tracking with plans to review information provided by utilities over the next few years and implement a commonly defined measure for these areas in the future. As a result, each utility may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- ### First Contact Resolution

First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

For NBHDL, First Contact Resolution is measured based on the number of customer concerns that are escalated formally to NBHDL's President or directly to the OEB. NBHDL's staff endeavor to resolve all customer concerns directly, however, calls can be escalated to department managers either by customer request or in cases where management input is required. Much like the front-line staff, management makes every attempt to resolve the concern in a matter that satisfies the customer and meets internal policies. As a customer centric service provider, NBHDL staff and management are typically able to resolve customer issues, however, in 2020 two (2) concerns were escalated to the OEB. This represents less than .02% of NBHDL's 24,000 customers.

A large proportion of customer complaints are related to the overall cost of hydro, which is a real concern for everyday people and businesses across the Province. This focus on cost was further exacerbated by the national impacts of the COVID19 pandemic. NBHDL recognizes the impact costs have on customers and we strive to find on-going and sustainable efficiencies within the business, however, NBHDL is only responsible for approximately 28% of the total bill for residential customers; the remaining 72% of costs are collected or distributed by NBHDL on behalf of various provincial entities. NBHDL is the frontline for the broader electricity sector and with this position comes the responsibility for answering customers' questions and concerns that are the result of the actions of other sector participants and outside the scope of NBHDL's direct control. This can be both challenging and frustrating for customers. 2020 saw NBHDL put customer needs even further to the forefront in an effort to alleviate the strain of the pandemic. Custom payment plans, waived late fees and a delayed rate increase were all done in an effort to assist customers in a very challenging year. Several of these initiatives will continue into 2021.

In all instances of customer concerns, the issue is addressed directly and every attempt is made to ensure the proper processes and policies are in place, and followed, to prevent future escalations and to ensure fairness to all customers and NBHDL while delivering an efficient customer service experience.

- ### Billing Accuracy

After consultation with electricity distributors, the OEB has prescribed a measurement of billing accuracy which must be used by all utilities. An industry target of 98% billing accuracy was established.

In 2020 just over 304,000 bills were issued to customers and NBHDL achieved a billing accuracy of 98.71% (99.87% in 2019), exceeding the prescribed OEB target of 98%. Over the last five years, NBHDL has averaged 99.55% in this metric and continuously monitors its billing accuracy and processes to identify opportunities for improvement and to ensure accurate bills are produced for customers. NBHDL considers it important to note that a single large billing error could potentially have an outsized effect on this statistic. Billing errors, when they do occur, are resolved quickly.

- **Customer Satisfaction Survey Results**

The OEB introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the OEB is allowing electricity distributors' discretion as to how they implement this measure.

Customer satisfaction is an important measure of customer loyalty and trust. In an environment where the electricity sector receives a high amount of attention in the media, maintaining customer satisfaction is a priority for NBHDL. NBHDL attempts to engage our customers throughout the year at community events, online through social media and through bill inserts and website messaging. NBHDL strives to maintain customer satisfaction through ongoing efforts to communicate relevant and timely customer information.

For the 2020 filing, NBHDL engaged a qualified market research organization for the bi-annual formal customer satisfaction survey. This survey type is widely utilized among LDCs in Ontario and the results of the survey contribute to benchmarking scores from electric utility customers across Canada. The results of the survey provided a snapshot of performance based on customer responses related to 4 categories: Electrical Service Reliability, Billing Accuracy and Options, Customer Service, and Communications. These measures combine for an "Overall Customer Satisfaction Index Score" of 86%. This figure compares consistently to prior scorecards, however, it should be noted that a new survey provider was engaged for the 2020 scorecard and, while comparable, the overall question and methodologies would differ.

Considering the delicate nature of the province's energy portfolio and the public perception thereof, NBHDL takes pride in knowing the vast majority of its customers are satisfied with our performance. NBHDL believes that this metric provides an overall picture of customer experience and satisfaction and will use this result for future comparisons until such time as the OEB determines a measure across the industry.

NBHDL will continue to use the bi-annual survey results to benchmark improvement and to identify additional opportunities to enhance customer satisfaction. Ongoing, daily interactions will be supported through enhanced engagement by way of a focus group of our highest consumption customers, ensuring communication channels are open, accessible and provide us with additional best practices moving forward. When deemed safe to do so, NBDHL will also be present at local trade shows, Chamber of commerce meetings, as well as gatherings with local contractors, and small to medium-sized businesses specifically. NBHDL continues to enhance and invest in our social media channels, according to feedback, to ensure messaging reaches customers quickly, and an easy channel for the community to request information, direction, or clarity on any subject.

Most importantly, NBHDL has begun working on an annual Sustainability Report, to update and inform the community on all aspects of the current business, our motivation and future intentions, as well as highlights from the previous year.

Safety

NBHDL is committed to protecting our workforce, customers, the public and the environment. In addition to achieving compliance with applicable laws, we strive for excellence in our environmental, health and safety performance through adopting good management practices and setting clear objectives and targets for achieving continual improvement. To achieve this, we ensure that environmental, health and safety management accountabilities and responsibilities are clearly defined and understood, that our employees are competent and effectively trained, and that appropriate resources are made available.

In 2020 NBHDL did not encounter a lost time incident. As part of its on-going commitment to safety, NBHDL will undertake extensive investigations and evaluations of the current practices, make recommendations, and implement those recommendations by reviewing any incident with all staff and retrain qualified personnel on the safe use of all equipment. Lost time incidents are only one measure of safe work practices. Ensuring each employee demonstrates safety as a value is integral to safe work. This reinforces our safety culture established in 2017 as it instills awareness, involvement, accountability, and continuous improvements in order to ensure that incidents are avoided and every worker returns home safely every day.

- **Public Safety**

The OEB introduced the Safety measure in 2015. This measure looks at safety from a customers' point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDCs are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. This survey differs from NBHDL's customer satisfaction survey in that it targets the general public regardless of whether they were an LDC customer. The questions on the survey are standardized across the province. NBHDL's Public Awareness of Electrical Safety survey result was 81% and was conducted in early 2020. This result has been consistent since 2015.

  - **Component B – Compliance with Ontario Regulation 22/04**

Over the past five years, NBHDL was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by the company's strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objectives based on electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

  - **Component C – Serious Electrical Incident Index**

NBHDL has not had any serious incidents due to contact with its infrastructure by the public over the last five years.

System Reliability

As a percentage of total sustained outages in the NBHDL system, the majority causes continue to be attributed to the following OEB categories: Foreign Interference, Tree Contacts, and Defective Equipment. Since the NBHDL system is predominantly overhead with a substantial portion running through rural areas, trend data will always correlate with the number and severity of storms that roll through the City each year. NBHDL is also an embedded distributor to Hydro One and as such, will experience loss of supply. Loss of Supply is not a variable that NBHDL can alter in an effort to improve reliability.

Outages that are caused by tree contacts are mitigated with a cyclical Vegetation Management Program. NBHDL's goal is to achieve a new standard of a 5-year cycle, by changing from primarily trimming/topping to performing full removals in order to address the high number of large trees located in close proximity to live conductors. Once all areas within NBHDL's service territory are completed to the new standard, it is expected that the overall number of tree related outages will be reduced and in turn, since trees will be at a much greater separation from poles and high voltage lines, there will be a reduction in the potential of animal contact situations (reducing foreign interference outages). In addition, the new standards will help reduce tree related damage in storm situations and make the system safer for the general public and Power Line Maintainers.

As a proud and active member of the North Bay community, NBHDL has committed to doing its part in restoring the tree canopy in the urban part of the City. As such, NBHDL has continued to maintain efforts to re-green the City while addressing the need for safe tree clearance with respect to power lines. NBHDL put this program on pause in 2020 in an effort to limit discretionary interactions with customer due to COVID19. But to date, NBHDL has planted over 500 new trees as part of the re-greening campaign.

Outages involving defective equipment are mitigated through periodic inspections of the distribution system, regular maintenance activities, and system renewal and rejuvenation projects. NBHDL is committed to reducing outages caused by equipment failure and continues to invest in upgrading its system and rebuilding its aging infrastructure.

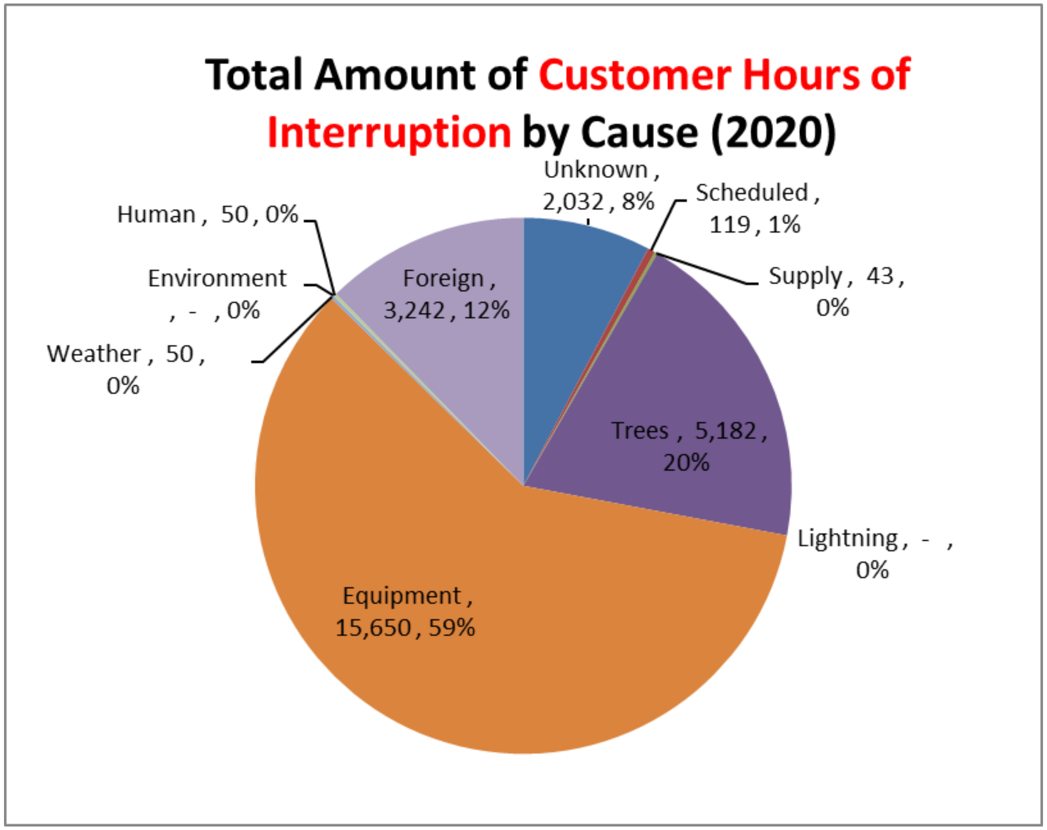
- **Average Number of Hours that Power to a Customer is Interrupted**

During normal hours of operations, NBHDL's control room can remotely manage the local grid rerouting power and dispatching crews to respond to outages quickly and efficiently. Outside hours of operations, NBHDL maintains an emergency response crew on call to restore power as quickly as possible at all times.

In 2020, NBHDL's average number of hours in which power to a customer was interrupted (outage hours not including supply disruptions) was 1.08 (1.16 in 2019) and below the distributor target of 1.52. NBHDL's goal is to have its system reliability trend in an improved manner over a five-year period; however, it is important to note that in any given year, outage hours will correlate with storm occurrences and severity. In 2020, Tree Contact and Foreign Interference related outages accounted for a combined 32% (40% in 2019) of the hours in which power to a customer was interrupted, while Defective Equipment was responsible for 59%. While the increase in Defective Equipment is significant compared to 2019 (13%), it is due to fewer incidents in 2019 that affected a comparatively higher number of customers for a shorter period of time.

- **Average Number of Times that Power to a Customer is Interrupted**

In 2020, NBHDL's average number of customer interruptions (i.e., frequency) was 0.78 and well below the distributor target range of 1.31. As stated above, occurrence of storms is a significant factor in annual reliability statistics. Foreign Interference and Tree Contact related outages accounted for 26% of the number of times in which power to a customer was interrupted while Defective Equipment was responsible for 60%. While the increase in Defective Equipment is significant compared to 2019 (4%), the circumstances explained in the bullet above detail the difference.



Asset Management

- **Distribution System Plan Implementation Progress**

Distribution System Plan (DSP) implementation progress is a performance measure instituted by the OEB in 2013. Consistent with other new measures, utilities were given an opportunity to define it in the manner that best fits their organization. The DSP outlines a utility's forecasted capital expenditures, over a five- year period, required to maintain (and for some utilities expand) the distributor's system to serve its current and future customers. This measure is intended to assess NBHDL's effectiveness at planning and implementing the DSP.

NBHDL owns and operates seventeen (17) municipal stations, has almost 575,000 meters of overhead lines and underground cable circuits and there are fifty-seven (57) distribution feeders, eight (8) sub-transmission feeders, and 4,030 distribution transformers.

NBHDL has based the DSP implementation progress as a percentage (%) of budgeted gross capital spending compared to actual spending. NBHDL achieved 102% of the DSP forecasted budget of $6.1M in 2020. In 2020, NBHDL was in the sixth year of Cost of Service Cycle and as such, its DSP progress is based on the previously approved DSP forecast that was intended to take NBHDL through a 5 year period. As part of its current Cost of Service application NBHDL has filed an updated DSP to see it through the 2021 to 2025 period.

NBHDL completed significant construction work totaling $3.6M in the City in 2020. A major project on Ski Club Road continued as part of an ongoing effort to revitalize two major 44kV sub-transmission circuits. Two major undergrounding projects continued on Shores Acres and Lovell Ave. Customer demand work, and general operational requirements such as building upgrades, substation upgrades, IT requirements and planned updates to the fleet also occurred in 2020.

NBHDL makes every effort to maximize the utilization of assets without compromising reliability or safety and will continue to do so in the future while executing on the DSP. In an effort to manage costs and keep rates low, NBHDL anticipates that capital spending will remain reasonably stable and paced for the 2021 - 2025 planning horizon. Throughout 2019 and 2020, NBHDL has been working on the completion of a new DSP; this will cover the upcoming 5-year period (2021-2025) and will be a guide to maintaining a safe and reliable distribution system that incorporates appropriate planning, pacing and cost effectiveness.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2020 for the ninth year in a row NBHDL was placed in Group 3, which is defined as having actual costs within +/- 10% of predicted costs. Group 3 is considered "average efficiency" – in other words, NBHDL's costs are within the average cost range for distributors in the Province of Ontario. In 2020, 46% (27 distributors) of the Ontario distributors were ranked as "average efficiency"; 44% were ranked as "more efficient"; 10% were ranked as "least efficient". A core objective of NBHDL is to maintain in Group 3.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of NBHDL's capital and operating costs and dividing this cost figure by the total number of customers that NBHDL serves. The cost performance result for 2020 is $715/customer which is a $17 (2.3%) decrease per customer over 2019. The average increase over the last 5 years is approx. 1.2% per year. This total cost figure does not reflect NBHDL's actual costs. Rather, these figures represent econometric values derived by the PEG model in order to rank Ontario utilities on a comparative "same size" basis. The total cost used in these measures reflects the mature state of development seen in Northern Ontario and in North Bay; an aging population with increased demands on service.

Similar to all distributors in the province, NBHDL has experienced increases in its total costs required to deliver quality and reliable services to customers.
Province wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in vegetation management, new information systems technology, cyber-security and the renewal of the distribution system, have all contributed to increased operating and capital costs. NBHDL will continue to replace distribution assets proactively along a carefully managed timeframe in a manner that balances system risks and customer rate impacts as will be demonstrated in NBHDL's 2021 rate application.

From the fall of 2019 through to the fall of 2020 NBHDL was actively involved in a Cost of Service Application that detailed all operating and capital requirements of the company from 2015 through to a forecast of 2021. The 2021 costs then form the basis of rates for the next 5 years. Staff at the OEB and intervenors, representing various customer groups, have gone through thousands of pages of evidence supporting NBHDL's case for rates and test that evidence for reasonability, prudence and justification.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the cost per customer calculation above, but the total cost is divided by the kilometers of line that NBHDL operates to serve its customers. NBHDL's 2020 rate is $30,270 per Km of line, a $658 (2.1%) decrease over 2019; with an average increase of 1.4% per year over the last 5 years. NBHDL's capital focus is asset renewal which is simply replacing (and in some cases reducing) the same Km of line, not increasing total Km; this results in increasing renewal costs each year, but with the same (or lower) total Km of line. NBHDL also experiences a low level of growth in its total kilometers of lines due to a low annual customer growth rate.

The City of North Bay has experienced limited growth typical of municipalities in Northern Ontario. Utilities situated in or clustered around the GTA have growth both in customers and lines to service these customers, which are often built by developers. Their metrics can be different than areas or communities served more remote from Toronto. NBHDL uses multiple measures, beyond those used by the OEB to compare 'same size' utilities, to monitor the efficiency of the business and strives to manage costs while delivering on capital and maintenance programs, and will continue to do so.

Connection of Renewable Generation

Ontario runs two renewable generation programs. FIT ("Feed-in Tariff") applicants are those customers setting up solar or other renewable generation equipment to generate more than 10 kW of electricity at a time. MicroFIT applicants are those customers applying to generate electricity at a level less than or equal to 10 kW of electricity at a time. NBHDL encouraged customers to participate in the FIT and microFIT programs, and has been able to meet all timelines for assessments and connections. The microFIT program stopped accepting applicants at the end of 2017.

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization from the Electrical Safety Authority. NBHDL has three (3) FIT installations with generating capacity of 1.88 MW, including the Merrick Landfill. NBHDL currently has 6 Net-Metering connections. This continues to be a positive option for customers looking to connect with smaller electrical generation installations.

- **New Micro-embedded Generation Facilities Connected On Time**

In 2017, the microFIT program ceased accepting new applications. NBHDL currently has 48 microFIT generators with a capacity of 429.74 kW.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

NBHDL's current ratio decreased from 1.69 in 2019 to 1.58 in 2020 primarily due to a decrease in accounts receivable and cash, which is offset partially by decreases in accounts payable and customer. NBHDL's current ratio in subsequent years is expected to remain at current levels or slightly increase with future borrowing and continual management of accounts receivable and liabilities.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. NBHDL's exchange of new debt combined with a lower net income which is reflected in a slight increase in the ratio to 1.14 in 2020 as compared to 1.03 in 2019. This ratio of 1.14 represents an actual debt to equity of 53.3% to 46.7% respectively.

NBHDL manages its liquidity and debt to support its financial obligations and execute its operating and capital plans as well as maintain capacity and access to capital to support future development of the business. NBHDL's liquidity and leverage ratios are strong compared to the required covenant levels imposed by lenders.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

NBHDL's last Cost of Service application was finalized in November 2015 and approved rates included an expected (deemed) regulatory return on equity of 9.30%. The OEB allows a distributor to earn within +/- 3% of the expected 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.

- **Profitability: Regulatory Return on Equity – Achieved**

NBHDL's achieved return in 2020 was 4.64%, which is outside the +/-3% range allowed. Given that NBHDL was in the sixth year of a cost or service cycle and has submitted an updated cost of service application for 2021 rates, this is not an indication of long-term overall health or performance and is aligned with expected and planned performance. NBHDL also notes the considerable strain on all businesses COVID 19 has caused. While the challenges that affected NBHDL don't compare to other businesses that faced closures, reacting to the pandemic did cause a shift in resources and spending priorities. NBHDL also deferred an approved May 2020 rate increase in response to the pandemic in an effort to assist its customers and our community during these trying times. This was a direct reduction in ROE as NBHDL did not seek to recover the deferred increase and this is reflected in NBHDL's 2020 results.

No regulatory review was deemed necessary by the OEB.

Note to Readers of 2020 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - Espanola Regional Hydro Distribution Corporation

10/22/2021

Performance Outcomes	Performance Categories	Measures		2016	2017	2018	2019	2020	Trend	Target	
										Industry	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		100.00%	100.00%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		100.00%	98.18%	100.00%	98.55%	97.10%		90.00%	
		Telephone Calls Answered On Time		76.20%	72.62%	70.67%	63.04%	68.04%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.17 %	99.60	99.73	99.23	99.7			
		Billing Accuracy		99.95%	99.95%	99.89%	99.98%	99.94%		98.00%	
		Customer Satisfaction Survey Results		87 %	87 %	87%	91.00	91			
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		85.00%	84.00%	84.00%	85.00%	85.00%			
		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]		0.55	0.35	0.16	0.35	0.21			0.34
		Average Number of Times that Power to a Customer is Interrupted [2]		1.10	0.10	0.06	0.17	0.06			0.30
	Asset Management	Distribution System Plan Implementation Progress		On Track	On Track	On Track	On Track	on track			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$670	$661	$683	$758	$716			
		Total Cost per Km of Line [3]		$15,702	$15,421	$16,003	$17,789	$23,597			
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).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time		0.00%							
		New Micro-embedded Generation Facilities Connected On Time		100.00%	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)		1.34	1.17	1.22	0.83	1.01			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.22	1.17	1.12	-22.35	-7.99			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.12%	9.12%	9.12%	9.12%			
			Achieved	6.29%	2.45%	4.12%	-9.46%	-6.45%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. 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.

Legend:

5-year trend: up | down | flat

Current year: target met | target not met

2020 Scorecard Management Discussion and Analysis ("2020 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2020Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2019, North Bay (Espanola) Acquisition Inc. acquired Espanola Regional Hydro Distribution Corporation and amalgamated under the name Espanola Regional Hydro Distribution Corporation ("ERHDC").

ERHDC exceeded all customer focus performance targets in 2020. ERHDC increased telephone calls answer on time to 68% in 2020. Given the transition of employees working from home during the Covid-19 pandemic, ERHDC is pleased with this result of meeting the industry target of 65%. ERHDC maintained a significantly high performance in all other customer focus areas.

ERHDC had a strong performance in Operational Effectiveness in 2020. Not only has ERHDC exceeded the 5-year rolling average distributor target in both reliability performance metrics, for a seventh year in a row, ERHDC had zero public incidents in relation to safety. For the ninth consecutive year, ERHDC has maintained an efficiency assessment rating of Group 2 which is defined as having actual costs between 10% and 25% below predicted costs under the Pacific Economics Group LLC (PEG) model.

In 2019, due to the acquisition being fully financed, ERHDC incurred significant increases in its debt to equity ratios and reduced ratios tied to liquidity. With the proposed future amalgamation with North Bay Hydro Distribution Inc. (North Bay Hydro) in 2022 this situation will be temporary, but until the amalgamation is approved and completed, ERHDC will continue to operate as an independent LDC. Once amalgamated, the New North Bay Hydro will have strong liquidity and debt service ratios as well as more optimal debt to equity ratios with financial capacity for any necessary borrowing. As a result, the 2020 financial ratios saw a similar outcome of to that of 2019. ERHDC received approval from the OEB to increase distribution rates effective May 1, 2021 which will result in better financial ratios for the upcoming 2021 fiscal year.

ERHDC will continue working towards maintaining its high-level of customer satisfaction and operational effectiveness. The details provided in this report on service quality, customer satisfaction, safety, system reliability, asset management, cost control, and financial ratios confirm ERHDC's continued strong performance in 2020.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2020, ERHDC connected 21 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, with 100% of these connections completed within the five-day timeline prescribed by the Ontario Energy Board (OEB). This score exceeds the OEB mandated threshold of 90%.

- **Scheduled Appointments Met on Time**
  In 2020, ERHDC scheduled 67 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, meter locates etc.) ERHDC achieved 97.10% which exceeded the OEB target of 90%.

- **Telephone Calls Answered on Time**
  In 2020, ERHDC's Customer Care Department received 3,645 calls from its customers. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 68.04% of the time. ERHDC achieved the OEB target of 65%.

Customer Satisfaction

- **First Contact Resolution**
  ERHDC's First Contact Resolution was measured by tracking the number of electric related calls that were escalated to a Senior Customer Care Representative, Supervisor, or Manager. This was accomplished by tracking two specific call types in our Customer Information System (CIS), which are queried to provide the number of customer concerns that were escalated.

  In 2020, ERHDC had 3,645 calls, of which 11 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.70%. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**
  ERHDC issued 39,660 bills for the period from January 1, 2020 – December 31, 2020 and achieved an accuracy of 99.94%. This compares favorably to the prescribed OEB target of 98%. ERHDC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  In 2020, ERHDC did not conduct a survey. The survey is completed every 2 years with the most recent one completed in 2019 with a score of 91%. The next survey will be conducted in 2021 and will be done by UtilityPULSE. The survey will include questions focused on the key areas of: power quality and reliability; price; billing and payment; communication; customer service experience; and corporate image.

Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two years. The questions on the survey are standardized across the province.

ERHDC's third safety awareness survey was conducted in early 2020 and resulted in a score of 85%. This was a 1% improvement over the previous Safety survey.

  - **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans and specifications, and the inspection of construction before they are put in service.

Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. All these elements are evaluated as a whole to determine the status of compliance. Over the past ten years, ERHDC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). ERHDC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures. ERHDC's target for this metric is to remain fully compliant with Ontario Regulation 22/04.

- **Component C – Serious Electrical Incident Index**

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to the ESA any serious electrical incidents of which they become aware within 48 hours after the occurrence. ERHDC had no serious electrical incidents to report for the period January 1 through December 31, 2020. The utility has not had a serious electrical incident to report in the last seven years. For 2020, the results are zero incidents with a rate of 0.0 per 100 km of line.

ERHDC remains strongly committed to both the safety of staff and the general public. ERHDC regularly provides its customers with electrical safety information via its website and bill inserts. Additionally, ERHDC has made significant maintenance and capital infrastructure investments in the past several years to enhance system safety and reliability.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**
  The System Average Interruption Duration Index (SAIDI) of 0.21 in 2020 was below the target of 0.34. There are ongoing efforts to maintain reliability including vegetation management practices and the proactive inspection and replacement of aging infrastructure.

- **Average Number of Times that Power to a Customer is Interrupted**
  The System Average Interruption Frequency Index (SAIFI) of .06 in 2020 was below the target of 0.30. Consistent with SAIDI, there are ongoing efforts to maintain reliability including vegetation management practices and the proactive inspection and replacement of aging infrastructure.

Asset Management

- **Distribution System Plan Implementation Progress**
  ERHDC completed a 1 year DSP with its 2021 Cost of Service Application. ERHDC remains on track with the implementation of that DSP in 2021.

Cost Control

- **Efficiency Assessment**
  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as the number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2019:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDC's in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	9
2	Actual costs are 10% to 25% below predicted costs	More Efficient	17
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	27
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

  In 2020, for the ninth consecutive year, ERHDC was again placed in Group 2, attesting to its ability to keep costs in line with predictions. efficiency performance based on the PEG model was under the predicted costs by 22.5% between 2018 and 2020.

- **Total Cost per Customer**
  Total cost per customer is calculated as the sum of ERHDC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model) and dividing this cost figure by the total number of customers that ERHDC serves. The cost performance result for 2020 is $716 per customer which is a 5.6% decrease over 2019. ERHDC had increased costs in 2019 due to higher administrative costs from the sale of ERHDC to North Bay Hydro. In 2020, costs came back down more in line with years prior to 2019.

  Overall, ERHDC's Total Cost per Customer has increased on average by 1.02% per annum over the period 2016 through 2020. ERHDC will continue to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on

ERHDC’s capital spending plans.

- **Total Cost per Km of Line**
  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. ERHDC's 2020 rate is $23,597 per Km of line. In 2020, ERHDC completed an internal audit of Km of line as part of the DSP and 2021 Cost of service application. This resulted in an update of 141 km of line in 2019 to 101 km of line in 2020.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority.

  For the year 2020, no CIA requests were received. However, ERHDC maintains its internal processes to ensure all applications are processed within the prescribed timelines when they are received.

- **New Micro-embedded Generation Facilities Connected on Time**
  In 2020, ERHDC did not receive any requests to connect any new micro-embedded generation facilities.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being “liquid”. The higher the number, the more “liquid” and the larger the margin of safety to cover the company’s short-term debts and financial obligations.

  ERHDC’s current ratio went from 0.83 in 2019 to 1.01 in 2020. Until ERHDC amalgamates with North Bay Hydro, it will continue to see fluctuations in its debt to equity ratios and ratios tied to liquidity due to financing structure.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  ERHDC has a debt to equity ratio of negative -7.99 in 2020 which is below the deemed capital structure. As noted above, the financing structure is temporary, and the leverage ratio tied to liquidity will continue to be low until the amalgamation occurs. ERHDC received approval for new rates effective May 1, 2021. This will increase distribution revenues and help alleviate the debt to equity ratio over the next 5 years.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  ERHDC's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.12%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected 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.

- **Profitability: Regulatory Return on Equity – Achieved**
  ERHDC's ROE is a negative -6.45% for the year end as a result of unfavorable distribution revenue and increased OM&A costs. ERHDC received approval from the OEB for increased distribution rates effective May 1, 2021 as part of its 2021 Cost of Service rate application. These new rates will better align ERHDC's distribution revenues and costs to achieve a better ROE for 2021.

Note to Readers of 2020 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix E

December 31, 2019 and December 31, 2020 Audited Financial Statements of ERHDC and NBHDL

North Bay Hydro Distribution Limited
Financial Statements
For the year ended December 31, 2019

North Bay Hydro Distribution Limited
Financial Statements
For the year ended December 31, 2019

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Independent Auditor's Report

To the Shareholder of North Bay Hydro Distribution Limited

Opinion

We have audited the financial statements of North Bay Hydro Distribution Limited (the Entity), which comprise the statement of financial position as at December 31, 2019, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

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 Auditor's Responsibilities for the Audit of the Financial Statements section of our 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 ethical 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 these 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.

Auditor's 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 auditor's 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 these 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 auditor's 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 auditor's 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.

We 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.

Chartered Professional Accountants, Licensed Public Accountants

North Bay, Ontario
April 7, 2020

North Bay Hydro Distribution Limited
Statement of Financial Position
Expressed in Canadian Dollars
For the year ended December 31, 2019

	Note	2019	2018
Assets			
Current assets			
Cash and short-term investments		$ 11,244,116	$ 7,791,709
Accounts receivable	8	10,074,129	10,830,576
Unbilled revenue		6,010,011	5,867,434
Payment in lieu of taxes receivable	9	-	142,088
Inventory	13	679,184	738,723
Prepaid expenses		608,002	704,509
Total current assets		28,615,442	26,075,039
Non-current assets			
Property, plant and equipment	5	72,267,651	69,301,631
Investment in associate	7	360,120	-
Financial instrument asset		513,527	1,194,928
Deferred taxes	9	1,325,427	1,666,724
Total non-current assets		74,466,725	72,163,283
Total assets		103,082,167	98,238,322
Regulatory deferral account debit balances	4	1,062,183	666,902
Total assets and regulatory deferral account balances		$ 104,144,350	$ 98,905,224

Expressed in Canadian Dollars

	Note	2019	2018
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 11,740,444	$ 9,558,632
Payment in lieu of taxes	9	87,718	-
Deferred revenue		789,289	841,982
Customer deposits - current	8	94,281	73,005
Current portion of long-term debt	17	4,010,219	3,431,093
Total current liabilities		16,721,951	13,904,712
Long-term liabilities			
Customer deposits – long-term	8	732,674	737,239
Contributions in aid of construction	6	3,890,009	3,500,338
Employee future benefits	10	4,536,742	4,256,659
Long-term debt	17	36,428,435	35,060,008
Total non-current liabilities		45,587,860	43,554,244
Total liabilities		62,309,811	57,458,956
Shareholder's Equity			
Share capital	14	19,511,601	19,511,601
Retained earnings		19,862,835	19,059,353
Accumulated other comprehensive (loss)		(205,399)	(11,059)
		19,657,436	19,048,294
Total shareholder's equity		39,169,037	38,559,895
Total liabilities and shareholder's equity		101,478,848	96,018,851
Regulatory deferral account credit balances	4	2,665,502	2,886,373
Total liabilities, equity and regulatory deferral account credit balances		$ 104,144,350	$ 98,905,224

Commitments and Contingencies (Note 18 and 19)
Subsequent events (Note 23)

Signed on behalf of the Board of Directors by

Director

Director

North Bay Hydro Distribution Limited
Statement of Comprehensive Income
Expressed in Canadian Dollars
For the year ended December 31, 2019

	Note	2019	2018
Revenue			
Electricity sales		$ 70,498,828	$ 67,424,198
Other		649,219	746,080
		71,148,047	68,170,278
Expenses			
Cost of power		57,947,018	55,082,974
Operating expenses	15	6,739,764	6,430,199
Depreciation and amortization		2,981,841	2,854,199
Loss on disposal of property, plant and equipment		90,272	25,920
Loss (gain) on foreign exchange		1,406	(915)
		67,760,301	64,392,377
Income from operating activities		3,387,746	3,777,901
Finance income	16	392,466	382,647
Finance costs	16	(1,205,365)	(1,091,700)
Earning in associate	7	605,148	-
Change in interest rate swap	17	(681,401)	(140,775)
Income before provision for payment in lieu of income taxes		2,498,594	2,928,073
Provision for payment in lieu of income taxes			
Current	9	122,584	-
Deferred		411,365	832,823
		533,949	832,823
Profit for the year before net movements in regulatory deferral account balances		1,964,645	2,095,250
Net movement in regulatory deferral account balances related to profit or (loss)	4	(243,503)	114,430
Net movement in regulatory deferral account balances arising from deferred tax movement		411,365	832,823
Profit for the year and net movements in regulatory deferral account balances		2,132,507	3,042,503
Other comprehensive income:			
Remeasurement of employee future benefits (net of (2019 – ($70,068) in tax) (2018-$55,974)	9	(194,340)	155,249
Net and comprehensive income for the year		$ 1,938,167	$ 3,197,752

North Bay Hydro Distribution Limited
Statement of Changes in Equity
Expressed in Canadian Dollars
For the year ended December 31, 2019

	Share Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total
Balance at January 1, 2018	$ 19,511,601	($166,308)	$ 17,275,704	$ 36,620,997
Profit for the year and net movements in regulatory deferral account balances	-	-	3,042,503	3,042,503
Other comprehensive income, net of tax		155,249		155,249
Dividends paid	-	-	(1,258,854)	(1,258,854)
December 31, 2018	19,511,601	(11,059)	19,059,353	38,559,895
Profit for the year and net movements in regulatory deferral account balances	-	-	2,132,507	2,132,507
Other comprehensive income, net of tax	-	(194,340)	-	(194,340)
Dividends paid	-	-	(1,329,025)	(1,329,025)
Balance at December 31, 2019	$ 19,511,601	$ (205,399)	$ 19,862,835	$39,169,037

North Bay Hydro Distribution Limited
Statement of Cash Flows
Expressed in Canadian Dollars
For the year ended December 31, 2019

	2019	2018
Cash Flows From Operating Activities		
Profit for the year and net movements in regulatory deferral account balances	$ 2,132,507	$ 3,042,503
Adjustments to reconcile income to net cash used in operating activities:		
Depreciation and amortization	2,981,841	2,854,199
Amortization of contributions in aid of construction	(93,371)	(80,619)
Deferred income taxes	411,365	832,823
Employee future benefit expense	275,840	177,966
Loss on disposal of property, plant and equipment	80,337	25,920
Change in associate	(605,148)	
Change in interest rate swap	681,401	140,775
	5,864,772	6,993,567
Change in non-cash operating working capital:		
Accounts receivable	1,184,717	(3,311,361)
Unbilled revenue	(142,577)	462,103
Inventory	59,539	(128,498)
Prepaid expenses	96,508	187,692
Accounts payable and accrued liabilities	2,181,812	(1,016,705)
Deferred revenue	(52,695)	455,568
Payment in lieu of taxes	229,806	(121,038)
Customer deposits	16,711	(24,988)
Net cash flows from operating activities	9,438,593	3,496,340
Cash Flows from investing activities		
Proceeds from sale of property, plant and equipment	132,692	3,432
Purchase of property, plant and equipment	(6,589,158)	(6,615,336)
Dividends received and accrued from associate	245,028	-
Changes in regulatory deferral account balances	(616,152)	(1,774,695)
Cash used in investment activities	(6,827,590)	(8,386,599)
Cash Flows from financing activities		
Contributions received in aid of construction	483,042	558,617
Dividends paid	(1,329,025)	(1,258,854)
Employee future benefits paid	(260,166)	(269,846)
Repayment of long-term debt	(3,552,447)	(2,980,612)
Advances of long-term debt	5,500,000	4,500,000
Cash provided by financing activities	841,404	549,305
Net increase (decrease) in cash	3,452,407	(4,340,954)
Cash and short-term investments, beginning of year	7,791,709	12,132,663
Cash and short-term investments, end of year	$ 11,244,116	$ 7,791,709

1. Corporate Information

North Bay Hydro Distribution Limited's (the "Company") main business activity is the distribution of electricity under authority of the Ontario Energy Board ("OEB") Act, 1998. The Company owns and operates an electricity distribution system, which delivers electricity to approximately 24,401 customers located in North Bay, Ontario.

Operating in a regulated environment exposes the Company to regulatory and recovery risk.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory balances. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. North Bay Hydro Distribution Limited is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The address of the Company's corporate office and principal place of business is 74 Commerce Crescent, North Bay, Ontario, Canada.

The sole shareholder of the Company is the Corporation of the City of North Bay.

2. Basis of Preparation

a) Statement of compliance

The financial statements of North Bay Hydro Distribution Limited have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The financial statements were authorized for issue by the Board of Directors on April 7, 2020.

b) Basis of measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Company's functional currency, and all values are rounded to the nearest dollar, unless when otherwise indicated.

c) Judgment and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgment in applying the Company's accounting policies. The areas involving critical judgments and estimates in applying

2. Basis of Preparation (continued)

accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The recognition and measurement of regulatory deferral account balances (Note 4);
- The determination of useful lives of property, plant and equipment (Note 5);
- The calculation of the impairment of accounts receivable (Note 8);
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 9); and
- The calculation of the net future obligation for certain unfunded health, dental and life insurance benefits for the Company's retired employees (Note 10).

In addition, in preparing the financial statements the notes to the financial statements were ordered such that the most relevant information was presented earlier in the notes and the disclosures that management deemed to be immaterial were excluded from the notes to the financial statements. The determination of the relevance and materiality of disclosures involved significant judgement.

3. Adoption of New Accounting Standards

Accounting standards, interpretations and amendments effective for accounting years beginning on or after January 1, 2019 are listed below and did not materially affect the Company's financial statements.

IFRS 16 Leases (IFRS 16)

IFRS 16 Leases supersedes IAS 17 Leases. IFRS 16 provides a single lessee accounting model, requiring the recognition of assets and liabilities for all leases, unless the lease term is 12 months or less, or the underlying asset is of low value. The standard eliminates the distinction between operating and finance leases from the perspective of the lessee, however, the perspective of the lessor remains largely in line with previous IAS 17 requirements with the distinction between operating leases and finance leases being retained. All contracts that meet the definition of a lease will be recorded in the statement of financial position with a "right of use" asset and a corresponding liability. The asset is subsequently accounted for as property, plant and equipment or investment property and the liability is unwound using the interest rate inherent in the lease.

The Company adopted IFRS 16 using the modified retrospective approach without restatement of comparative figures. The definition of a lease under IFRS 16 was applied only to contracts entered into or changed on or after January 1, 2019. The company concludes that there are no contracts in 2019 of material value, or over a lease term of 12 months, that have been entered into that would require recognition of right-of-use assets and lease liabilities. The Company elected to apply the practical expedient to not reassess whether a contract is, or contains a lease at the date of initial application. Contracts entered into before the transition date that were not identified as leases under IAS 17 and IFRIC 4 were not reassessed. The Company has elected not to recognize right-of-use assets and lease liabilities for some leases of low value assets based on the value of the underlying asset when new or for short-term leases with a lease term of 12 months or less.

3. Adoption of New Accounting Standards (Continued):

IFRIC Interpretation 23 Uncertainty over Income Tax Treatments (IFRIC 23)

IFRIC 23 provides guidance on the accounting for current and deferred tax liabilities and assets in circumstances in which there is uncertainty over income tax treatments. The Interpretation requires:

- An entity to contemplate whether uncertain tax treatments should be considered separately, or together as a group, based on which approach provides better predictions of the resolution;
- An entity to determine if it is probable that the tax authorities will accept the uncertain tax treatment; and
- If it is not probable that the uncertain tax treatment will be accepted, measure the tax uncertainty based on the most likely amount or expected value, depending on whichever method better predicts the resolution of the uncertainty.

The adoption of IFRIC 23 did not have a material impact on the Company's financial statements.

4. Regulatory deferral account balances

In accordance with IFRS 14, the Company has continued to apply the accounting policies it applied in accordance with the pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation. These are referred to as regulatory deferral account balances. Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets.

Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s) that are expected to be returned to consumers in future periods through the rate-setting process.

Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s) that are expected to be recovered from consumers in future periods through the rate-setting process. Management continually assesses the likelihood of recovery of regulatory balances. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

The balances and movements in the regulatory deferral account balances shown below are presented net of related deferred taxes. These deferred taxes are not presented within the total deferred tax asset balances shown in Note 9.

Expressed in Canadian Dollars

4. Regulatory deferral account balances (continued)

All amounts deferred as regulatory deferral account balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	Remaining recovery period (years)	2019	2018
Regulatory Deferral Account Debit Balances			
Cost of Power (i)	1 – 4	$ 532,660	$ 381,987
Cost of Power – Global Adjustment (i)	1 - 4	170,956	-
Disposition/rec – 2014 - 2018 (ii)	1 - 4	38,630	-
LRAMVA (iii)	1 – 4	185,986	181,983
Other (vi)	1 – 4	133,951	102,932
Total Regulatory Deferral Account Debit Balances		$ 1,062,183	$ 666,902

	Remaining recovery period (years)	2019	2018
Regulatory Deferral Account Credit Balances and related Deferred Tax			
Cost of Power - Wholesale Market Service (i)	1 – 4	$ (750,952)	$ (607,380)
Cost of Power – Global Adjustment (i)	1 - 4	-	(25,913)
Disposition/rec – 2014 - 2018 (ii)	1 - 4	-	(433,182)
Retail cost variances (iv)	1 – 4	(151,130)	(131,763)
Deferred income taxes (v)	5 - 25	(1,325,427)	(1,666,724)
Other (vi)	1 – 4	(437,993)	(21,411)
Total Regulatory Deferral Account Credit Balances and related Deferred Tax		$ (2,665,502)	$ (2,886,373)

4. Regulatory deferral account balances (continued)

In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the year in which they relate. As a result, the net effect on income for the period is as stated below.

i. Cost of Power

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service charged to the Company for the operation of the wholesale electricity market and grid, including commodity and global adjustment, various wholesale market settlement charges and transmission charges. Under the OEB's direction, the Company has deferred the settlement variances that have occurred since May 1, 2002 in accordance with the AP Handbook. Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. The Company did not recognize carrying charge income related to the retail settlement variance accounts for external reporting purposes prior to December 31, 2003.

The OEB allows the variances to be deferred which would normally be recorded as revenue for unregulated businesses under Modified IFRS (MIFRS). In absence of rate regulation, revenues in 2019 would have been lower by $33,015 (2018 - lower by $1,110,543).

As a component of the yearly Incentive Regulation Mechanism (IRM) rate application process, "Group 1" account balances (which are composed of Low Voltage, Wholesale Market, Network, Connection, Power and the Smart Meter Entity charge) are reviewed and will qualify for disposition if balances, including carrying charges, exceed a preset threshold per kWh. The Company has not proposed any disposition in the pending 2020 IRM application for 2020 rates. In 2018, NBHDL disposed of 2016 audited balances for Group 1 accounts – see Note ii.

ii. Disposition/recovery – 2014, 2015, 2016, 2017, 2018

Disposition/recovery – 2014 On August 30, 2013, the Company filed an IRM application for 2014 distribution rates (EB-2013-0157) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On March 6, 2014, the OEB approved the disposition of net regulatory assets of $864,885 and net regulatory liabilities of $1,594,828 over a one year period commencing May 1, 2014 and ending April 30, 2015. The amounts consisted of principal balances as of December 31, 2012 with carrying charges projected to April 30, 2014. NBHDL will seek disposition of the net residual balance of $17,602 related to the 2014 disposition in a future rate application.

Disposition/recovery – 2015 On December 18, 2014, the Company filed a COS application for 2015 distribution rates (EB-2014-0099) with the OEB which included a request seeking disposition of the balances for regulatory assets and liabilities. On July 16, 2015, the OEB approved the disposition of net regulatory assets of $1,554,186 and net regulatory liabilities of ($4,662,850) which included Group 1 and 2 balances, CGAAP and LRAMVA accounts. The Group 1 and 2 amounts consisted of principal balances as of December 31, 2013 with carrying charges projected to April 30, 2015 for a net total of $455,076 being collected from customers over a one year period commencing July 1, 2015 and ending June 30, 2016.

4. Regulatory deferral account balances (continued)

The PP&E – CGAAP and transitional amounts were refunded to customers over a two year period beginning July 1, 2015 and ending June 30, 2016. The amount owed to customers included the disposition of the regulatory liability of ($3,793,377). The LRAMVA amount approved for disposition included the lost revenue for OPA programs up to December 31, 2013 plus carrying charges projected to April 30, 2015 for a total amount of $229,637 being collected from customers over a one-year period commencing July 1, 2015 and ending June 30, 2016. NBHDL will seek disposition of the net residual balance of ($6,973) related to the 2015 disposition in a future rate application.

Disposition/recovery – 2016 On March 23, 2016, the Company filed an IRM application for 2016 distribution rates (EB-2015-0092) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On May 5, 2016, the OEB issued a decision approving the disposition of net regulatory assets of $935,707. The amounts consisted of principal balances as of December 31, 2014 with carrying charges projected to April 30, 2016. The OEB approved disposition of $950,051 over a one year period commencing May 1, 2016 and ending April 30, 2017 for the Global Adjustment amount; the remaining Group 1 account balances netting ($14,344) will be refunded to customers in a future rate application. NBHDL will seek disposition of the net residual balance of $60,470 related to the 2016 disposition in a future rate application.

Disposition/recovery – 2017 On September 26, 2016, the Company filed an IRM application for 2017 distribution rates (EB-2016-0214) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets, liabilities and LRAMVA accounts. On February 8, 2017, the OEB issued a decision approving the disposition of net regulatory liabilities of ($691,352). The amounts consisted of principal balances as of December 31, 2015 with carrying charges projected to April 30, 2017. The OEB approved disposition and recovery of net regulatory liabilities over a one-year period commencing May 1, 2017 and ending April 30, 2018. The LRAMVA amount approved for disposition included the lost revenue for OPA programs up to December 31, 2014 plus carrying charges projected to April 30, 2017 for a total amount of $191,584 being collected from customers over a one-year period commencing May 1, 2017 and ending April 30, 2018. NBHDL will seek disposition of the net residual balance of ($24,954) related to the 2017 disposition in a future rate application.

Disposition/recovery – 2018 On October 16, 2017, the Company filed an IRM application for 2018 distribution rates (EB-2017-0065) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On March 22, 2018, the OEB issued a decision approving the disposition of net regulatory liabilities of ($1,300,650). The amounts consisted of principal balances as of December 31, 2016 with carrying charges projected to April 30, 2018. The OEB approved disposition over a one-year period commencing May 1, 2018 and ending April 30, 2019. NBHDL will seek disposition of the net residual balance of ($7,515) related to the 2018 disposition in a future rate application.

4. Regulatory deferral account balances (continued)

iii. Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

On April 26, 2012 the OEB released the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) which included accounting direction on the treatment of lost revenues from forecasted/unforecasted Conservation and Demand Management (CDM) results on distribution revenue due to variances from forecasted throughput used to establish distribution rates.

The Board established an LRAM variance account (“LRAMVA”) to capture the differences between the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor’s franchise area) and the level of CDM program activities included in the distributor’s load forecast (i.e. the level embedded into rates). At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications.

In the 2014 COS application, the OEB approved disposition of LRAMVA amounts related to CDM programs up to December 31, 2013 in the amount of $221,924; this is now included in the disposition/recovery – 2015 account. On February 8, 2017, the OEB approved disposition of LRAMVA amounts related to CDM programs up to December 31, 2014 in the amount of $191,584; this is now included in the disposition/recovery – 2017 account.

Under the Conservation First Framework (“CFF”), for programs that take place from 2015 to 2020, distributors were to treat lost revenues in a similar manner as those from the 2010-2014 programs with respect to the impact of lost revenues. Distributors were to capture the differences between the results of actual, verified impacts of authorized CDM activities against the LRAMVA threshold included in the most recent Cost of Service application. Accordingly, the Company has recorded $178,128 in the LRAMVA deferral account; this represents amounts related to CDM programs from 2015 to 2017. On March 21, 2019 the OEB announced the discontinuation of the CFF and the establishment of a scaled down interim framework for the balance of 2019 and 2020, the delivery of which will be done centrally by the IESO. The cancelation of the CFF has the potential to limit or eliminate the Company’s ability to seek recovery for any future revenue variances caused by conservation programs beyond the current application.

On November 25, 2019, the Company filed an IRM application for 2020 distribution rates (EB-2019-0057) with the OEB which included a request seeking recovery of the LRAMVA amounts related to CDM programs from 2015-2018. The amount requested, $274,497, includes carrying charges through to April 30, 2020 and an additional request for a specific program. This request is under review and not recorded as LRAMVA as at December 31, 2019. The Company has requested a recovery period of one year form May 1, 2020 through April 30, 2021. This is a pending application and is subject to the approval of the OEB.

4. Regulatory deferral account balances (continued)

iv. Retail cost variances

Retail cost variances were established to record the difference between the amount billed and the incremental costs of providing retail services and to record the difference between the amount billed in relation to a service transaction request and the incremental costs of providing the initial screening and actual processing services for the service transaction request. Under the OEB's direction, the Company has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the Company has deferred these recoveries in accordance with the AP Handbook.

The OEB allows the variances to be deferred which would normally be recorded as revenue for unregulated businesses under IFRS. In absence of rate regulation, revenues in 2019 would have been higher by $19,268 (2018 - higher by $19,072). The deferred balance for unapproved settlement variances continues to be calculated in accordance with the OEB's direction. The OEB approved disposition of audited 2013 balances in the 2014 COS application - see Note ii.

v. Deferred Income Taxes

The recovery from, or refund to, customers of future income taxes through future rates is recognized as a regulatory deferral account balance. The Company has recognized a deferred tax asset of $1,325,427 (2018 – $1,666,724) arising from the recognition of regulatory deferral account balances and a corresponding regulatory deferral account credit balance of $1,325,427 (2018 - $1,666,724). The deferred tax asset balance is presented within the total regulatory deferral account balances presented in the statement of financial position.

vi. Other

2019 costs relate to carrying charges on accounts included as regulatory credits, increased OEB cost assessments and incremental revenue related to pole attachment charges and decreased tax expenditures to tax changes. In 2016, in addition to an increase in the OEB’s internal budget, the OEB also revised its Cost Assessment Model to reflect a change in the methodology used to apportion costs. These changes resulted in a material shift in the allocation of costs. The OEB established a variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model. NBHDL has recorded $31,474 in incremental cost assessment increases in 2019 (2018- $30,586) in the deferral account in accordance with the guidance on the use of the variance account. In September 2018 and again in January 2019, the OEB revised its approved pole attachment charges for distributors. The OEB established a variance account for electricity distributors to record the revenue difference between these new rates and previously approved rates. In 2019 NBHDL has recorded ($257,220) as incremental revenue (2018 - $21,354). In July 2019, the OEB established a variance account to record the effects of the Accelerated Investment Incentive (AII). The AII created new capital cost allowance (CCA) rules that translated to a material difference between taxes built into rates using the OEB Tax Model and taxes that NBHDL would pay. The OEB also established that this account should reflect the change dating back to the beginning of the AII (November 2018). In 2019, NBHDL, recorded regulatory liabilities of $171,649 and $6,254 for 2019 and 2018 respectively.

4. REGULATORY DEFERRAL ACCOUNT BALANCES (CONTINUED)

vii. Future Applications

On Nov 25, 2019, NBHDL filed a IRM rate application (EB-2019-0057) for rates commencing May 1, 2020. This application is subject to the approval of the OEB. The application includes an annual delivery rate adjustment of 1.7% and a request for recovery of LRAMVA balances totaling $274,497 - Note 4-iii.

In August 2020, NBHDL intends to file its cost of service (COS) application for 2021 rates. As part of this application, NBHDL will seek the disposition of all Group 1 and Group 2 balances for regulatory assets and liabilities as of December 31, 2019. These balances will includes the net residual balances described in 4ii) above and will be subject to OEB review and approval.

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Management continually assesses the likelihood of recovery of regulatory assets and realization of regulatory liabilities. If recovery and realization through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made

Expressed in Canadian Dollars

5. Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated amortization. Costs may include direct material, labour, contracted services, overhead, engineering costs and interest on funds used during construction that are considered applicable to construction. Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as property, plant and equipment since they support the Company's distribution system reliability. Upon disposal the cost and accumulated amortization of assets are relieved from the respective accounts and any gain or loss is reflected in operations.

Depreciation of property, plant and equipment is recorded in the Statement of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period.

The estimated useful lives are as follows:

Distribution Assets:	
Building and fixtures	30 - 50 years
Substations	40 - 50 years
Poles, towers and fixtures	45 years
Overhead conductor and devices	60 years
Underground conduit and conductor	40 - 50 years
Distribution transformers	40 years
Overhead and underground services	40 – 60 years
Distribution meters	10 - 25 years
General Assets:	
Buildings	25 – 50 years
Office equipment	10 years
Computer equipment	5 years
Transportation equipment	5 - 8 years
Small tools and miscellaneous equipment	10 years
Load management controls	6 years
System supervisory equipment	15 – 20 years

Land is not depreciated.

Expressed in Canadian Dollars

5. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

		Electrical Distribution Assets		General Assets		Work in process		Total
Cost								
Balance at January 1, 2018	$	112,344,878		12,176,538		2,611,071		127,132,487
Additions		6,642,285		297,763		(324,712)		6,615,336
Disposals		(286,282)		(53,374)		-		(340,048)
Balance at December 31, 2018		118,700,881		12,420,536		2,286,359		133,407,775
Balance at January 1, 2019		118,700,881		12,420,536		2,286,359		133,407,775
Additions		6,298,481		799,673		(508,995)		6,589,159
Disposals / Reallocation		(596,504)		(89,410)		(442,669)		(1,128,582)
Balance at December 31, 2019		124,402,858		13,130,799		1,334,695		138,868,352
Depreciation and impairment losses								
Balance at January 1, 2018		52,953,119		8,609,523		-		61,562,642
Depreciation for the year		2,262,348		591,852		-		2,854,200
Disposals		(256,932)		(53,766)		-		(310,698)
Balance at December 31, 2018	$	54,958,535	$	9,147,609	$	-	$	64,106,144
Balance at January 1, 2019		54,958,535		9,147,609		-		64,106,144
Depreciation for the year		2,385,235		596,606		-		2,981,841
Disposals		(397,873)		(89,411)		-		(487,284)
Balance at December 31, 2019	$	56,945,897	$	9,654,804	$	-	$	66,600,701
Carrying amounts:								
At December 31, 2018	$	63,742,346	$	3,272,927	$	2,286,359	$	69,301,631
At December 31, 2019	$	67,456,961	$	3,475,995	$	1,334,695	$	72,267,651

Expressed in Canadian Dollars

6. Revenue Recognition

As a licensed distributor, the Company 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 Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Revenues from the sale and distribution of electricity is recognized over time on an accrual basis upon delivery of electricity, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Sale and distribution of electricity revenue is comprised of customer billings for distribution service charges. Customer billings for distribution service charges are recorded based on meter readings, and are generally due within 30 days of the billing date.

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions vary by project and are based on the criteria set forth in the Distribution System Code. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The continuity of deferred contributions in aid of construction is as follows:

	December 31 2019	December 31 2018
Deferred contributions, net, beginning of year	$ 3,500,338	$ 3,022,340
Contributions in aid of construction received	483,042	558,617
Contributions in aid of construction recognized as distribution revenue	(93,371)	(80,619)
Deferred contributions, net, end of year	$ 3,890,009	$ 3,500,338

All contributions in aid of construction are cash contributions. There have not been any contributions of property plant and equipment.

Expressed in Canadian Dollars

7. INVESTMENT IN ASSOCIATE

The Company has an equity interest in Ecobility; a company owned by five different shareholders all of whom own, operate, or are affiliated with, a local distribution company. The company operates out of Sudbury and Toronto and facilitates the management and delivery of Provincial conservation programs across the service territories of each owner and other locations throughout the Province.

Of the 143,860 shares issued, the company owned 16.66% at year end. Of the five voting shares, the Company holds one. This equity interest is measured on the balance sheet using the equity method of accounting. The Company's share of preliminary net earnings of $2,579,837 for the year is $343,840. Dividends recorded against the investment throughout the year totaled $250,068. The investee had total assets of $5,869,575 and shareholders' equity of $2,672,850 as at December 31, 2019.

8. ACCOUNTS RECEIVABLE, UNBILLED REVENUE AND CUSTOMER DEPOSITS

	December 31 2019	December 31 2018
Accounts receivable due from related parties	$ 1,685,626	$ 953,905
Short term advances to related parties	-	2,733,926
Customer accounts receivable	8,520,035	7,257,277
Loss allowance	(131,532)	(114,532)
Total accounts receivable	$ 10,074,129	$ 10,830,576

a) Recognition and initial measurement
The Company initially recognizes accounts receivable on the date on which they are originated and recognizes unbilled service revenue on the date on which the Company delivers the electricity but has not yet billed the customer. Similar to customer billings, unbilled revenue for distribution service charges are recorded based on meter readings. Accounts receivable and unbilled service revenue are initially measured at fair value.

b) Classification and subsequent measurement
Accounts receivable and unbilled service revenue are classified and subsequently measured at amortized cost because they meet the solely payments of principal and interest criterion and are held within a business model whose objective is to hold financial assets in order to collect contractual cash flows. The carrying amount is reduced through the use of a loss allowance and the amount of the related loss allowance is recognized in profit or loss. Subsequent recoveries of receivables and unbilled service revenue previously provisioned are credited to profit or loss.

c) Fair value measurement
Due to its short-term nature, the carrying amounts of accounts receivable and unbilled service revenue approximates their fair value.

8. Accounts Receivable, Unbilled Revenue and Customer Deposits (continued)

d) Credit risk

Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as deposits, which are reported separately from the Company's own cash and cash equivalents. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 2%.

Due to its short-term nature, the carrying amount of the accounts receivable due from related parties and other accounts receivable approximates its fair value. Unbilled service revenue reflects the electricity delivered but not yet billed to customers. Customer billings generally occur within 30 days of delivery. The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Company has approximately 24,410 customers, the majority of which are residential. The Company considers an account receivable to be in default when the customer is unlikely to pay its credit obligations in full, without recourse by the Company, such as realizing security (if any is held). Accounts are past-due (in default) when the customers have failed to make the contractually requirements payments when due, which is generally within 30 days of the billing date.

The Company considers an account receivable to be credit-impaired when the customer has amounts more than 90 days past the billing date. In determining the allowance for doubtful accounts, the Company considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances.

The change in allowance for doubtful accounts related to a $121,132 bad debt expense for the year and accounts receivable write off of $159,457. The carrying amount of accounts receivable is reduced through the use of an allowance for impairment. Subsequent recoveries of receivables previously provisioned were $55,349 (2018 - $59,061) and are credited to the income statement. The balance of the allowance for impairment at December 31, 2019 is $131,556 (2018 - $114,532). The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2019, approximately $104,659 (2018 - $191,727) is considered 60 days past due.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

Customer deposits represents cash deposits from electricity distribution customers and retailers, as well as construction deposits. Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

Subsequent to year end, the credit risk related to the organization's accounts receivable has increased due to the impact of COVID-19, which could lead to potential uncollectible amounts or slowing collections. This may impact the amount of cash collections related to accounts receivable balances in fiscal 2020 could impact the Company's cash flow requirements.

Expressed in Canadian Dollars

8. Accounts Receivable, Unbilled Revenue and Customer Deposits (continued)

	December 31 2019	December 31 2018
Customer deposits – current	$ 94,281	$ 73,005
Customer deposits – long-term	732,674	737,239
Total customer deposits	$ 826,955	$ 810,244

a) Recognition and initial measurement

The Company initially recognizes customer deposits on the date on which the Company received the deposit. Customer deposits are initially measured at fair value.

b) Classification and subsequent measurement

Customer deposits are classified and subsequently measured at amortized cost, using the effective interest rate method.

c) Fair value measurement

The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance.

9. Payments in Lieu of Taxes Payable

The Company is a Municipal Electricity Utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate income taxes each year to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. PILs expense comprises of current and deferred tax. Current tax and deferred tax are recognized in comprehensive income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances.

Significant judgment is required in determining the provision for PILs. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company’s current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

Expressed in Canadian Dollars

9. Payments in Lieu of Taxes Payable (continued)

Significant components of the payments in lieu of taxes expense are as follows:

a. Expense

The Company's provision for PILs is calculated as follows:

	2019	2018
Income before provision for payment in lieu of income taxes	$ 2,498,594	$ 2,928,073
Regulatory assets/liabilities added (deducted) for tax purposes	(274,885)	(885,896)
Net change in reserves (EFB)	15,675	(91,880)
Capital cost allowance (greater than) less than amortization expense	(1,807,071)	(2,110,256)
Other items	(741,404)	(121,823)
Unrealized (gain) loss	681,401	140,775
(Gain) loss on disposal of assets	90,272	25,920
Income (loss) for tax purposes	464,619	Nil
Statutory Canadian federal and provincial tax rate	26.50%	26.50%
Provision for PILs (recovery)	122,584	-
Total current tax provision	$ 122,584	$ Nil

b. Deferred Taxes

Components of deferred taxes are as follows:

	2019	2018
Property, plant and equipment	$ 49,549	$ 392,232
Employee future benefits	1,202,237	1,128,015
Regulatory Assets / Liabilities	73,641	146,478
Total deferred tax assets	$ 1,325,427	$ 1,666,725

10. Employee Future Benefits

Employee future benefits other than pension provided by the Company include medical and insurance benefits. These benefit plans provide benefits to certain employees when they are no longer providing active service.

The cost of these benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, the cost of these benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

The calculation is performed by a qualified actuary using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. The valuation is performed every third year or when there are significant changes to workforce. A full valuation was performed in 2019.

Remeasurements of the defined benefit obligation are recognized directly within equity in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs are recognized in the Statement of Comprehensive Income in operating expenses, and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized on the Statement of Comprehensive Income in finance costs, and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

The plan is exposed to a number of risks, including:

Interest rate risk: decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation.

Longevity risk: changes in the estimation of mortality rates of current and former employees.

Health care cost risk: increases in cost of providing health, dental and life insurance benefits.

Expressed in Canadian Dollars

10. EMPLOYEE FUTURE BENEFITS (CONTINUED)

The Company has a defined benefit life insurance and health care plan covering all active employees and most retirees. Information about the Company's defined benefit life insurance and health care plan is as follows:

	2019	2018
Prepaid benefit liability, beginning of year	$ 4,256,659	$ 4,559,762
Expense for the year	275,841	177,966
Benefits paid during the year	(260,166)	(269,846)
Actuarial gains/losses recognized	264,408	(211,223)
Prepaid benefit liability, end of year	$ 4,536,742	$ 4,256,659
Fair value of plan assets	$NIL	$NIL

Included in wages and employee benefits and finance costs respectively, is a net benefit expense as follows:

	2019	2018
Total service cost of the plan for the year	$ 121,320	$ 34,281
Interest on average liabilities	154,521	143,685
Total Expense for the year	$ 275,841	$ 177,966

The main actuarial assumptions employed for the valuations are based on the full actuarial report performed in 2019. In 2019, the Company hired an outside consulting firm to update the actuarial valuation report based on the changes noted below, including an update of employee and retiree status.

Expected average remaining service life of active employees 13 years.

a. General Inflation / Salary Levels

In 2019, the actuarial report was based on salary scale assumption based on the Corporation’s management of 2% per annum up to 2022 and 3% per annum for 2023 onwards. This change reflected the Corporation’s bargaining agreements and consideration for increases in the salary scale in the long term. As such, in 2019 there was no inflation rate used in the valuation. In 2018, the future general inflation levels, as measured by changes in the Consumer Price Index (“CPI”), were assumed at 2% in 2018.

b. Interest (Discount) Rate

The obligation at year end, of the present value of future liabilities and the expense for the year ended, were determined using a discount rate of 3.1% (2018- 3.9%). The discount rate for 2019 reflects the assumed long-term yield on high quality bonds as at December 31, 2019 (most recent valuation date).

10. EMPLOYEE FUTURE BENEFITS (CONTINUED)

c. Medical Costs

Medical costs reflect cost increase assumptions from 2019 and continue to be assumed to increase 4.20% from 2020-2024, 5.3% from 2025-2034, 4.6% from 2035-2039, and 4% thereafter.

d. Dental Costs

Dental costs reflect cost increase assumptions from 2019 and continue to be assumed to increase at 4.5% from 2020-2024, 5.60% from 2025-2029, 5.30% from 2030-2034, 4.60% from 2035-2039 and 4% thereafter.

The Company's sick accrual is included above in the amount of $220,400 (2018 - $164,500) and is the accumulation of non-vested sick leave benefits under IAS 19 standards for financial reporting purposes. The Company hired an outside consulting firm to assess the future payments to be made as a result of the Company's employees' sick leave bank hours in 2019. The discount rate used in 2019 was 3.10% (2018 – 3.9%). The Future general salary and wage levels were assumed to increase at 2.0% per annum up to 2022 and 3.0% per annum thereafter.

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities.

11. RELATED PARTY TRANSACTIONS

The Company provides administrative and other services to an affiliated company, North Bay Hydro Services Inc ("Services").

The Corporation of the City of North Bay (the "City") is the 100% owner of North Bay Hydro Holdings Inc. which is the parent company of North Bay Hydro Distribution Limited, North Bay Hydro Services Inc. and Espanola Regional Hydro Distribution Corporation (amalgamated with North Bay (Espanola) Acquisition Inc. October 1, 2019).

Electrical energy is sold to the City at the same prices and terms as other electricity customers consuming equivalent amounts of electricity. Streetlight maintenance services are provided at rates determined in relation to other service providers. Other construction services are provided at cost.

The company has provided an inter-company loan arrangement to North Bay Hydro Services Inc. with a maximum authorized limit of $3.5 million. The interest rate on this facility is 3.45%. The loan balance at December 31, 2019 was $NIL (2018 - $2,733,926).

The following tables summarize the transactions that occurred between North Bay Hydro Distribution Limited and its affiliates.

Expressed in Canadian Dollars

11. Related Party Transactions (continued)

	Sale of Goods		Purchase of Goods		Amounts owed to (from)	
	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018	Year Ended December 31, 2019	Year Ended December 31, 2018
NBHS						
Contract services and other	$ 441,308	$ 372,060	$ -	$ -	$ -	$ -
Contracted Services	-	-	245,484	307,149	-	-
Total statement of earnings and retained earnings	441,308	372,060	245,484	307,149	-	-
Accounts receivable					(794,333)	(174,095)
Accounts payable	-	-	-	-	380,023	318,114
Loan Receivable					-	(2,733,926)
Total balance sheet	$ -	$ -	$ -	$ -	$ (414,310)	$(2,589,906)
ERHDC						
Accounts Receivable					(551,351)	(377,940)
NBEAI Total					$ (551,351)	$ (377,940)
Hydro Holdings						
Administration fees	$ -	$ -	$ 12,000	$ 12,000	$ -	$ -
Holdco total	$ -	$ -	$ 12,000	$ 12,000	$ -	$ -
City of North Bay						
Electrical energy sales	$ 3,519,935	$ 3,700,370	$ -	$ -	$ -	$ -
Construction activity sales	73,563	53,844	-	-	-	-
Street light maintenance	7,703	19,901	-	-	-	-
Fuel / water / other	-	-	102,017	306,873	-	-
CDM initiatives	-	-	-	25,265	-	-
Donations	-	-	-	1,250	-	-
Interest on promissory note	-	-		-	-	-
Total statement of earnings and retained earnings	$ 3,601,201	$ 3,774,115	$ 102,017	$ 333,688	$ -	$ -
Accounts receivable	-	-	-	-	(339,942)	(401,871)
Accounts payable	-	-	-	-	60,790	126,815
Total balance sheet	$ -	$ -	$ -	$ -	($279,152)	($275,056)

Management Compensation

During the year the Company compensated its senior management group $1,168,945 (2018 - $1,115,317), including salaries and benefits.

Expressed in Canadian Dollars

12. LOAN GUARANTEE

The company has a financial loan guarantee to a related company under common control; the guarantee covers the amount outstanding to two commercial lenders. The amount of debt outstanding, related to this financial guarantee at year end, was $9,907,801. The guarantee would be triggered if the related party defaulted on its financial obligations, primarily with respect to monthly debt payments. There is no collateral held for this guarantee and no fees were charged during the year in relation to this financial guarantee

13. INVENTORY

Cost of inventories comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value. The amount of inventories consumed by the Company and recognized as an expense during 2019 was $110,895 (2018 - $90,924).

Inventory consists of parts, supplies and materials held for future capital expansion or maintenance and are valued at the lower of cost, determined by the weighted average method, and replacement cost.

14. SHARE CAPITAL

Authorized:

Unlimited Common shares

The issued share capital is as follows:

	2019	2018
1,001 Common Shares	$ 19,511,601	$ 19,511,601

15. OPERATING EXPENSES BY NATURE

	2019	2018
Repairs and maintenance	$ 1,267,625	$ 1,087,545
Staff costs	3,713,425	3,384,856
General administration and overhead	1,549,622	1,707,658
Bad debts	121,132	167,985
Property taxes	87,960	82,155
	$ 6,739,764	$ 6,430,199

Expressed in Canadian Dollars

16. Finance Income and Finance Cost

	2019	2018
Finance Income:		
Interest income on receivables	$ 186,699	$ 207,164
Interest income on bank deposits	205,767	175,483
	$ 392,466	$ 382,647
Finance Cost:		
Interest on long-term debt	$ 1,050,844	$ 948,015
Net interest on employee future benefits	154,521	143,685
	$1,205,365	$1,091,700

17. Long-term Debt

The Company negotiated a loan with the Ontario Infrastructure Projects Corporation to provide funding for the Smart Meter project. The loan is a 10 year serial loan at an interest rate of 3.90% calculated on a semi-annual basis. The loan will be repaid in 120 monthly installments which will include both principal and interest. The loan balance at the end of the year was $116,667 (2018 - $816,667), of which is repayable within one year.

The Company's agreement with the Ontario Infrastructure Projects Corporation requires a debt service coverage ratio of 1.3 or higher, a debt to capital ratio lower than 60%, and a current ratio of 1.1:1 or higher. As part of the financing proposal, the OIPC agreed to waive any debt service coverage violation if working capital surplus was greater than the loan amount. The agreement also prevents the Company from making loans or paying dividends that would cause the violation of these covenants. As at December 31, 2018 the Company was in compliance with these covenants.

The Company has six term loans in the amounts of $4,000,000, $4,500,000, $6,000,000, $5,500,000 and two $5,000,000 loans with a Canadian Financial Institution and has entered into interest rate derivative agreements to manage the volatility of interest rates on long-term debt for each. Five of these loans are to be repaid over 120 months and one over 240 months with combined repayments of $286,175 per month principal and interest having fixed rates at 3.095%,3.55%, 2.45%, 2.36%, 2.88%, and 2.37% respectively.

The Company entered into a term loan in the amount of $19,500,000 to replace the existing loan agreement with the City of North Bay. This loan is to be repaid over 240 months with repayments of $103,331 per month principal and interest at a rate of 2.5%.

The fair value of these loans are $39,968,501 (2018- $37,674,438) which is estimated by obtaining market-to-market quotes from the Company's lending institutions. The quoted prices generally reflect the estimated amount that the Company would pay (receive) to settle these agreements at the statement of financial position date.

Expressed in Canadian Dollars

17. LONG-TERM DEBT (CONTINUED)

The Company must maintain Debt Service Coverage (DSC) ratio of not less than 1.20:1 on to remain in compliance with outstanding debt obligations. The Company has met these covenants at year-end.

Principal repayments for the next five years and thereafter are as follows:

2020	$ 4,010,219
2021	3,882,218
2022	3,866,670
2023	3,969,492
2024	3,999,848
Thereafter	20,710,207
	$ 40,438,654

The interest rates on these financial instruments are fixed and therefore the Company is not exposed to fluctuations in short-term interest rates in relation to these debts.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company has a planning and budgeting process in place to help determine the funds required to support the Company's normal operating requirements on an on-going basis. The Company strives to maintain a liquidity level that allows for sufficient funds to meet operational requirements so that obligations can be met as they become due.

The following table sets out the contractual maturities (representing undiscounted contractual cash flows) of financial liabilities:

December 31, 2018	60 days	< 1 year	1 – 5 years	> 5 years
Accounts payable	$9,558,632	$ -	$ -	$ -
Loans	568,646	2,865,064	17,122,187	17,935,207
	$10,127,278	$2,865,064	$17,122,187	$17,935,207

December 31, 2019	60 days	< 1 year	1 – 5 years	> 5 years
Accounts payable	$11,740,444	$ -	$ -	$ -
Loans	622,810	3,156,387	16,154,324	20,151,646
	$12,363,254	$3,156,387	$16,154,324	$20,151,646

18. CONTINGENCIES

The Company belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2019, the Company has not been made aware of any assessments for losses.

The Company has one outstanding claim against it and expects that any potential liability under this claim will be covered under the MEARIE liability policy.

19. COMMITMENTS

On October 9, 2009 the Company entered into a 15 year contract with Sensus Metering Systems Inc. to maintain and further develop the AMI system that meets the MEU functional specifications related to the Smart Meter Project. The contract contains 3 renewal terms of 5 years each. The Company elected to have the monthly fees billed in US dollars, instead of having the currency rate set on an annual basis in October of each year. Termination penalties apply if the Company cancels the contract without cause, the related fees are based on a sliding scale for the year this takes place and the fees associated with the service option selected. Annual fees in the amount of approximately $206,000 are expected to be incurred under this contract, however can fluctuate based on several factors including performance. This contract exposes the Company to currency risk with fluctuations in currency prices when it purchases US dollars to meet the payable commitments.

20. CREDIT FACILITY / LETTERS OF CREDIT

The Company has an authorized line of credit under a credit facility agreement with a Canadian chartered bank. The maximum draw permitted under this agreement is $1,000,000. At year end the Company had drawn $Nil (2018 - $Nil) under this facility.

The Company has available a revolving term facility with a maximum draw of $1,000,000 to finance the purchase of capital assets. At year end the Company had drawn $Nil (2018 - $NIL) under this facility.

The Company has a $3.6 million letter of credit with its bank provided to the IESO to secure the Company's hydro purchase obligations. The Company has provided its financial institution with a General Security Agreement as security for this obligation.

The Company's general banking agreement which encompasses the line of credit, revolving term facility and the letter of credit contains financial covenants which include a debt to capital ratio lower than 60% and a debt service coverage ratio of not less than 1:2 and positive free cash flow. Distributions in excess of free cash flow are permitted when financed by cash on hand. As at December 31, 2019 the Company was in compliance with these covenants.

The Company strives to maintain a liquidity level that allows for sufficient funds to meet operational requirements so that obligations can be met as they become due while minimizing interest expense. The Company monitors cash balances regularly and has access to short-term borrowings, should they be required, under its credit facility agreement. If the Company were to utilize this facility it would be exposed to fluctuations in short-term interest rates.

21. Pension Agreements

The Company makes contributions to the OMERS, which is a multi-employer pension plan, on behalf of all full-time members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to almost half a million active and retired members and approximately 1,000 employers.

Each year an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2019. The results of this valuation disclosed total actuarial liabilities of $107,687 million in respect of benefits accrued for service with actuarial assets at that date of $106,443 million indicating an actuarial deficit of $3,397 million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Company does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2019 was $430,516 (2018 - $437,483).

22. Capital Disclosures

The Company considers its capital to comprise its common share capital, retained earnings, and long-term debt.

In managing its capital, the Company’s primary objective is to ensure its continued ability to provide a consistent return for its equity shareholders through a combination of capital growth and through the payment of periodic dividends to its common shareholders. The Company also seeks to ensure that access to funding is available in order to maintain and improve the equipment used in operations and maintain financial ratios within the recommended guidelines as prescribed by the OEB. In order to achieve these objectives, the Company develops detailed annual operating budgets and seeks to maintain distribution revenue levels and control costs to enable the Company to meet its working capital requirements and strategic investment needs. In making decisions to adjust its capital structure to achieve these objectives, the Company considers both its short-term position and long-term operational and strategic objectives.

As at December 31, 2019 the Company is party to debt agreements that contain various covenants and is restricted from offering loans or paying dividends that would cause a violation of those covenants.

23. STANDARDS, AMENDMENTS AND INTERPRETATIONS NOT YET EFFECTIVE

There are no other standards, interpretations or amendments issued, but not yet effective that the Company anticipates may have a material effect on the financial statements once adopted.

24. SUBSEQUENT EVENTS

Subsequent to year end, the impact of COVID-19 in Canada and on the global economy increased significantly.

The global pandemic has disrupted economic activities and supply chains. Although the disruption from the virus is expected to be temporary, given the dynamic nature of these circumstances, the duration of business disruption and related financial impact cannot be reasonably estimated at this time. The entity's ability to continue to service debt and meet obligations as they come due is dependent on the continued ability to generate earnings and cash flows.

At this time, the full potential impact of COVID-19 on the entity is not known.

North Bay Hydro Distribution Limited
Financial Statements
For the year ended December 31, 2020

North Bay Hydro Distribution Limited
Financial Statements
For the year ended December 31, 2020

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Independent Auditor's Report

To the Shareholder of North Bay Hydro Distribution Limited

Opinion

We have audited the financial statements of North Bay Hydro Distribution Limited (the Entity), which comprise the statement of financial position as at December 31, 2020, and the statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2020, 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 Auditor's Responsibilities for the Audit of the Financial Statements section of our 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 ethical 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 these 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.

Auditor's 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 auditor's 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 these 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 auditor's 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 auditor's 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.

We 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.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants

North Bay, Ontario
March 29, 2021

North Bay Hydro Distribution Limited
Statement of Financial Position
Expressed in Canadian Dollars
For the year ended December 31, 2020

	Note	2020	2019
Assets			
Current assets			
Cash and short-term investments		$ 10,650,445	$ 11,244,116
Accounts receivable	7	8,462,168	9,866,229
Unbilled revenue		6,074,982	6,010,011
Payment in lieu of taxes receivable	8	123,130	-
Inventory	12	670,420	679,184
Prepaid expenses		531,969	608,002
Total current assets		26,513,114	28,407,542
Non-current assets			
Property, plant and equipment	4	75,244,891	72,267,651
Loan Receivable	10	904,196	207,900
Investment in associate	6	430,126	360,120
Financial instrument asset	16	-	513,527
Prepaid expenses – long-term		272,598	-
Deferred taxes	8	1,426,571	1,325,427
Total non-current assets		78,278,382	74,674,625
Total assets		104,791,496	103,082,167
Regulatory deferral account debit balances	3	1,276,624	1,062,183
Total assets and regulatory deferral account balances		$ 106,068,120	$ 104,144,350

North Bay Hydro Distribution Limited
Statement of Financial Position (continued)
Expressed in Canadian Dollars
For the year ended December 31, 2020

	Note	2020	2019
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	16	$ 9,587,989	$ 11,740,444
Payment in lieu of taxes	8	-	87,718
Deferred revenue		764,123	789,289
Customer deposits - current	7	59,114	94,281
Current portion of long-term debt	16	4,437,830	4,010,219
Total current liabilities		14,849,056	16,721,951
Long-term liabilities			
Customer deposits - long-term	7	626,741	732,674
Contributions in aid of construction	5	4,344,565	3,890,009
Employee future benefits	9	4,828,071	4,536,742
Long-term debt	16	37,848,969	36,428,435
Financial Instrument Liability	16	1,589,397	-
Total non-current liabilities		49,237,743	45,587,860
Total liabilities		64,086,799	62,309,811
Shareholder's Equity			
Share capital	13	19,511,601	19,511,601
Retained earnings		19,477,062	19,862,835
Accumulated other comprehensive (loss)		(409,792)	(205,399)
		19,067,270	19,657,436
Total shareholder's equity		38,578,871	39,169,037
Total liabilities and shareholder's equity		102,665,670	101,478,848
Regulatory deferral account credit balances	3	3,402,450	2,665,502
Total liabilities, equity and regulatory deferral account credit balances		$ 106,068,120	$ 104,144,350

Loan Guarantees (Note 11)
Commitments and Contingencies (Notes 17 and 18)
Uncertainty due to COVID - 19 (Note 23)

Signed on behalf of the Board of Directors by

_______________________ Director

_______________________ Director

North Bay Hydro Distribution Limited
Statement of Comprehensive Income
Expressed in Canadian Dollars
For the year ended December 31, 2020

	Note	2020	2019
Revenue			
Electricity sales		$ 78,496,465	$ 70,498,828
Other		586,277	649,219
		79,082,742	71,148,047
Expenses			
Cost of power		66,077,676	57,947,018
Operating expenses	14	6,787,692	6,739,764
Depreciation and amortization		3,158,923	2,981,841
Loss on disposal of property, plant and equipment		44,768	90,272
Loss (gain) on foreign exchange		2,785	1,406
		76,071,844	67,760,301
Income from operating activities		3,010,898	3,387,746
Finance income	15	207,024	392,466
Finance costs	15	(1,182,392)	(1,205,365)
Earning in associate	6	236,851	605,148
Change in interest rate swap	16	(2,102,924)	(681,401)
Income before provision for payment in lieu of income taxes		169,457	2,498,594
Provision for payment in lieu of income taxes			
Current	8	-	122,584
Deferred	8	(27,452)	411,365
		(27,452)	533,949
Profit for the year before net movements in regulatory deferral account balances		196,909	1,964,645
Net movement in regulatory deferral account balances related to profit or (loss)	3	(84,460)	(243,503)
Net movement in regulatory deferral account balances arising from deferred tax movement		(27,452)	411,365
Profit for the year and net movements in regulatory deferral account balances		84,997	2,132,507
Other comprehensive income:			
Remeasurement of employee future benefits (net of (2020 – ($73,693) in tax) (2019-$70,068)	8	(204,393)	(194,340)
Net and comprehensive income for the year		$ (119,396)	$ 1,938,167

North Bay Hydro Distribution Limited
Statement of Changes in Equity
Expressed in Canadian Dollars
For the year ended December 31, 2020

	Share Capital	Accumulated Other Comprehensive Income	Retained Earnings	Total
Balance at January 1, 2019	$ 19,511,601	($11,059)	$ 19,059,353	$ 38,559,895
Profit for the year and net movements in regulatory deferral account balances	-	-	2,132,507	2,132,507
Other comprehensive income, net of tax		(194,340)		(194,340)
Dividends paid	-	-	(1,329,025)	(1,329,025)
December 31, 2019	19,511,601	(205,399)	19,862,835	39,169,037
Profit for the year and net movements in regulatory deferral account balances	-	-	84,997	84,997
Other comprehensive income, net of tax	-	(204,393)	-	(204,393)
Dividends paid	-	-	(470,770)	(470,770)
Balance at December 31, 2020	$ 19,511,601	$ (409,792)	$ 19,477,062	$38,578,871

North Bay Hydro Distribution Limited
Statement of Cash Flows
Expressed in Canadian Dollars
For the year ended December 31, 2020

	2020	2019
Cash Flows From Operating Activities		
Profit for the year and net movements in regulatory deferral account balances	$ 84,997	$ 2,132,507
Adjustments to reconcile income to net cash used in operating activities:		
Depreciation and amortization	3,158,923	2,981,841
Amortization of contributions in aid of construction	(104,192)	(93,371)
Deferred income taxes	(27,452)	411,365
Employee future benefit expense	270,702	275,840
Loss on disposal of property, plant and equipment	44,768	80,337
Change in associate	(236,851)	(605,148)
Change in interest rate swap	2,102,924	681,401
	5,293,819	5,864,772
Change in non-cash operating working capital:		
Accounts receivable	707,766	1,184,717
Unbilled revenue	(64,972)	(142,577)
Inventory	8,766	59,539
Prepaid expenses	(196,565)	96,508
Accounts payable and accrued liabilities	(2,152,456)	2,181,812
Deferred revenue	(25,165)	(52,695)
Payment in lieu of taxes	(210,848)	229,806
Customer deposits	(141,101)	16,711
Net cash flows from operating activities	3,219,244	9,438,593
Cash Flows from investing activities		
Proceeds from sale of property, plant and equipment	3,900	132,692
Purchase of property, plant and equipment	(6,184,831)	(6,589,158)
Dividends received and accrued from associate	166,845	245,028
Changes in regulatory deferral account balances	522,507	(616,152)
Cash used in investment activities	(5,491,579)	(6,827,590)
Cash Flows from financing activities		
Contributions received in aid of construction	558,748	483,042
Dividends paid	(470,770)	(1,329,025)
Employee future benefits paid	(257,459)	(260,166)
Repayment of long-term debt	(4,151,855)	(3,552,447)
Advances of long-term debt	6,000,000	5,500,000
Cash provided by financing activities	1,678,664	841,404
Net increase (decrease) in cash	(593,671)	3,452,407
Cash and short-term investments, beginning of year	11,244,116	7,791,709
Cash and short-term investments, end of year	$ 10,650,445	$ 11,244,116

1. Corporate Information

North Bay Hydro Distribution Limited's (the "Company") main business activity is the distribution of electricity under authority of the Ontario Energy Board ("OEB") Act, 1998. The Company owns and operates an electricity distribution system, which delivers electricity to 24,492 customers located in North Bay, Ontario.

Operating in a regulated environment exposes the Company to regulatory and recovery risk.

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that restrict the electricity distribution business from achieving an acceptable rate of return that permits financial sustainability of its operations including the recovery of expenses incurred for the benefit of other market participants in the electricity industry such as transition costs and other regulatory balances. All requests for changes in electricity distribution charges require the approval of the OEB.

Regulatory developments in Ontario's electricity industry, including current and possible future consultations between the OEB and interested stakeholders, may affect distribution rates and other permitted recoveries in the future. North Bay Hydro Distribution Limited is subject to a cost of service regulatory mechanism under which the OEB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The address of the Company's corporate office and principal place of business is 74 Commerce Crescent, North Bay, Ontario, Canada.

The sole shareholder of the Company is the Corporation of the City of North Bay.

2. Basis of Preparation

a) Statement of compliance

The financial statements of North Bay Hydro Distribution Limited have been prepared by management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The financial statements were authorized for issue by the Board of Directors on March 29, 2021.

b) Basis of measurement

The financial statements have been prepared on a historical cost basis. The financial statements are presented in Canadian dollars (CDN$), which is also the Company's functional currency, and all values are rounded to the nearest dollar, unless when otherwise indicated.

c) Judgment and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgment in applying the Company's accounting policies. The areas involving critical judgments and estimates in applying

2. Basis of Preparation (continued)

accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The recognition and measurement of regulatory deferral account balances (Note 3);
- The determination of useful lives of property, plant and equipment (Note 4);
- The calculation of the impairment of accounts receivable (Note 7);
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 8);
- The calculation of the net future obligation for certain unfunded health, dental and life insurance benefits for the Company's retired employees (Note 9); and
- The assessment of the duration and severity of the developments related to the COVID-19 pandemic is subject to significant uncertainty; accordingly, judgments, estimates and assumptions related to the impact of the pandemic that may have a material adverse effect on the Company's operations, financial results and condition in future periods, made by management in the preparation of the financial statements are also subject to significant uncertainty.

In addition, in preparing the financial statements the notes to the financial statements were ordered such that the most relevant information was presented earlier in the notes and the disclosures that management deemed to be immaterial were excluded from the notes to the financial statements. The determination of the relevance and materiality of disclosures involved significant judgement.

3. Regulatory deferral account balances

In accordance with IFRS 14, the Company has continued to apply the accounting policies it applied in accordance with the pre-changeover Canadian GAAP for the recognition, measurement and impairment of assets and liabilities arising from rate regulation. These are referred to as regulatory deferral account balances. Regulatory deferral account balances are recognized and measured initially and subsequently at cost. They are assessed for impairment on the same basis as other non-financial assets.

Regulatory deferral account credit balances are associated with the collection of certain revenues earned in the current period or in prior period(s) that are expected to be returned to consumers in future periods through the rate-setting process. Regulatory deferral account debit balances represent future revenues associated with certain costs incurred in the current period or in prior period(s) that are expected to be recovered from consumers in future periods through the rate-setting process.

Management continually assesses the likelihood of recovery of regulatory balances. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

On January 5, 2021, the Company filed a Cost of Service Application with the OEB (EB-2020-0043). Included in this application was the proposed disposition and recovery of regulatory deferral account balances. The

Expressed in Canadian Dollars

3. Regulatory deferral account balances (continued)

proposed disposition includes eligible Group 1 and Group 2 balances, recovery of lost revenues, as well as the residual balances of prior approved disposition and recovery amounts.

The balances and movements in the regulatory deferral account balances shown below are presented net of related deferred taxes. These deferred taxes are not presented within the total deferred tax asset balances shown in Note 9.

All amounts deferred as regulatory deferral account balances are subject to approval by the OEB. As such, amounts subject to deferral could be altered by the regulators. Remaining recovery periods are those expected and the actual recovery or settlement periods could differ based on OEB approval. Due to previous, existing or expected future regulatory articles or decisions, the Company has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are comprised of:

	Remaining recovery period (years)		2020		2019
Regulatory Deferral Account Debit Balances					
Cost of Power (i)	1 – 4	$	333,921	$	532,660
Cost of Power – Global Adjustment (i)	1 - 4		468,143		170,956
Disposition/rec – 2014 - 2018 (ii)	1 - 4		39,186		38,630
LRAMVA (iii)	1 – 4		220,862		185,986
Other (vi)	1 – 4		214,512		133,951
Total Regulatory Deferral Account Debit Balances		$	1,276,624	$	1,062,183

	Remaining recovery period (years)		2020		2019
Regulatory Deferral Account Credit Balances and related Deferred Tax					
Cost of Power - Wholesale Market Service (i)	1 – 4	$	(1,022,332)	$	(750,952)
Retail cost variances (iv)	1 – 4		(168,137)		(151,130)
Deferred income taxes (v)	5 - 25		(1,426,571)		(1,325,427)
Other (vi)	1 – 4		(785,410)		(437,993)
Total Regulatory Deferral Account Credit Balances and related Deferred Tax		$	(3,402,450)	$	(2,665,502)

3. Regulatory deferral account balances (continued)

In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the year in which they relate. As a result, the net effect on income for the period is as stated below.

i. Cost of Power

This account is comprised of the variances between amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of non-competitive electricity service charged to the Company for the operation of the wholesale electricity market and grid, including commodity and global adjustment, various wholesale market settlement charges and transmission charges. Under the OEB's direction, the Company has deferred the settlement variances that have occurred since May 1, 2002 in accordance with the AP Handbook. Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. The Company did not recognize carrying charge income related to the retail settlement variance accounts for external reporting purposes prior to December 31, 2003.

The OEB allows the variances to be deferred which would normally be recorded as revenue for unregulated businesses under Modified IFRS (MIFRS). In absence of rate regulation, revenues in 2020 would have been higher by $470,118 (2019 - lower by $33,015).

As a component of the Cost of Service (COS) rate application process, "Group 1" account balances (which are composed of Low Voltage, Wholesale Market, Network, Connection, Power and the Smart Meter Entity charge) are reviewed for disposition through rates on what is typically a per kWh charge. The Company has proposed disposition of the Group 1 accounts in the pending 2020 Cost of Service application for 2021 rates in the net amount of ($114,932) which includes calculated interest through April 30, 2021.

On February 21, 2019, the OEB issued a letter entitled “Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment” as well as the related accounting guidance. The purpose of the direction was to standardize the accounting processes used by distributors related to RPP wholesale settlements and accounting procedures to improve the accuracy of the commodity pass-through accounts: Account 1588 – RSVA Power, and Account 1589 – Global Adjustment. In its 2019 IRM application decision (EB-2019-0057), the OEB instructed the Company to conduct a review of balances dating back to when Cost of Power variance accounts 1588 and 1589 were last approved for disposition (2016) and process adjustments, as applicable, in alignment with the new guidance. As a result of implementing these changes in 2020, the Company has made adjustments for 2017, 2018 and 2019 in the amounts of ($125,783), ($161,656) and ($154,944) respectively. These adjustments will be recovered from the IESO and refunded to customers as part of a future rate application.

ii. Disposition/recovery – 2014, 2015, 2016, 2017, 2018

Disposition/recovery – 2014 On August 30, 2013, the Company filed an IRM application for 2014 distribution rates (EB-2013-0157) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On March 6, 2014, the OEB approved the disposition of net regulatory assets of $864,885 and net regulatory liabilities of $1,594,828 over a one

3. REGULATORY DEFERRAL ACCOUNT BALANCES (CONTINUED)

year period commencing May 1, 2014 and ending April 30, 2015. The amounts consisted of principal balances as of December 31, 2012 with carrying charges projected to April 30, 2014. The Company has sought disposition of the net residual balance of $17,568 plus forecasted carrying charges related to the 2014 disposition in its pending COS application for 2021 rates.

Disposition/recovery – 2015 On December 18, 2014, the Company filed a COS application for 2015 distribution rates (EB-2014-0099) with the OEB which included a request seeking disposition of the balances for regulatory assets and liabilities. On July 16, 2015, the OEB approved the disposition of net regulatory assets of $1,554,186 and net regulatory liabilities of ($4,662,850) which included Group 1 and 2 balances, CGAAP and LRAMVA accounts. The Group 1 and 2 amounts consisted of principal balances as of December 31, 2013 with carrying charges projected to April 30, 2015 for a net total of $455,076 being collected from customers over a one year period commencing July 1, 2015 and ending June 30, 2016.

The PP&E – CGAAP and transitional amounts were refunded to customers over a two year period beginning July 1, 2015 and ending June 30, 2016. The amount owed to customers included the disposition of the regulatory liability of ($3,793,377). The LRAMVA amount approved for disposition included the lost revenue for OPA programs up to December 31, 2013 plus carrying charges projected to April 30, 2015 for a total amount of $229,637 being collected from customers over a one-year period commencing July 1, 2015 and ending June 30, 2016. The Company has sought disposition of the net residual balance of ($7,193) plus forecasted carrying charges related to the 2015 disposition in its pending COS application for 2021 rates.

Disposition/recovery – 2016 On March 23, 2016, the Company filed an IRM application for 2016 distribution rates (EB-2015-0092) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On May 5, 2016, the OEB issued a decision approving the disposition of net regulatory assets of $935,707. The amounts consisted of principal balances as of December 31, 2014 with carrying charges projected to April 30, 2016. The OEB approved disposition of $950,051 over a one year period commencing May 1, 2016 and ending April 30, 2017 for the Global Adjustment amount. The Company has sought disposition of the net residual balance of $60,961 plus forecasted carrying charges related to the 2016 disposition in its pending COS application for 2021 rates.

Disposition/recovery – 2017 On September 26, 2016, the Company filed an IRM application for 2017 distribution rates (EB-2016-0214) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets, liabilities and LRAMVA accounts. On February 8, 2017, the OEB issued a decision approving the disposition of net regulatory liabilities of ($691,352). The amounts consisted of principal balances as of December 31, 2015 with carrying charges projected to April 30, 2017. The OEB approved disposition and recovery of net regulatory liabilities over a one-year period commencing May 1, 2017 and ending April 30, 2018. The LRAMVA amount approved for disposition included the lost revenue for OPA programs up to December 31, 2014 plus carrying charges projected to April 30, 2017 for a total amount of $191,584 being collected from customers over a one-year period commencing May 1, 2017 and ending April 30, 2018. The Company has sought disposition of the net residual balance of ($25,040) plus forecasted carrying charges related to the 2017 disposition in its

3. REGULATORY DEFERRAL ACCOUNT BALANCES (CONTINUED)

pending COS application for 2021 rates.

Disposition/recovery – 2018 On October 16, 2017, the Company filed an IRM application for 2018 distribution rates (EB-2017-0065) with the OEB which included a request seeking disposition of the Group 1 balances for regulatory assets and liabilities. On March 22, 2018, the OEB issued a decision approving the disposition of net regulatory liabilities of ($1,300,650). The amounts consisted of principal balances as of December 31, 2016 with carrying charges projected to April 30, 2018. The OEB approved disposition over a one-year period commencing May 1, 2018 and ending April 30, 2019. The Company will seek disposition of the net residual balance of ($7,111) related to the 2018 disposition in a future rate application.

iii. Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

On April 26, 2012 the OEB released the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) which included accounting direction on the treatment of lost revenues from forecasted/unforecasted Conservation and Demand Management (CDM) results on distribution revenue due to variances from forecasted throughput used to establish distribution rates.

The Board established an LRAM variance account ("LRAMVA") to capture the differences between the results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area) and the level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates). At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications.

In the 2014 COS application, the OEB approved disposition of LRAMVA amounts related to CDM programs up to December 31, 2013 in the amount of $221,924; this is now included in the disposition/recovery – 2015 account. On February 8, 2017, the OEB approved disposition of LRAMVA amounts related to CDM programs up to December 31, 2014 in the amount of $191,584; this is now included in the disposition/recovery – 2017 account.

Under the Conservation First Framework ("CFF"), for programs that take place from 2015 to 2020, distributors were to treat lost revenues in a similar manner as those from the 2010-2014 programs with respect to the impact of lost revenues. Distributors were to capture the differences between the results of actual, verified impacts of authorized CDM activities against the LRAMVA threshold included in the most recent Cost of Service application. On March 21, 2019 the OEB announced the discontinuation of the CFF and the establishment of a scaled down interim framework for the balance of 2019 and 2020, the delivery of which will be done centrally by the IESO. The cancelation of the CFF has the potential to limit or eliminate the Company's ability to seek recovery for any future revenue variances caused by conservation programs beyond the current application.

In its IRM application for 2020 distribution rates (EB-2019-0057), the Company requested and was approved for the recovery of $274,497 for CDM programs from 2015-2018, which included carrying charges through to April 30, 2020. This recovery was originally slated to begin May 1, 2020, however,

3. REGULATORY DEFERRAL ACCOUNT BALANCES (CONTINUED)

as part of the provincial response to the COVID19 pandemic, the OEB allowed utilities the option to defer any approved May 1, 2020 rates increases. Subsequently, the Company began the recovery of this balance over a one-year period commencing November 1, 2020 and ending October 31, 2021. The balance as of December 31, 2020 for LRAMVA is $220,861.

In its COS application for 2021 rates (EB-2020-0043), the Company requested a further $246,420 in LRAMVA recovery including carrying charges to April 30, 2021. This amount relates to the persistence of CDM programs from 2015-2018 as well as new programs from January 1, 2019 to April 30, 2021 and is proposed to be recovered from May 1, 2021 to April 30, 2022. This is a pending application and is subject to the approval of the OEB.

iv. Retail cost variances

Retail cost variances were established to record the difference between the amount billed and the incremental costs of providing retail services and to record the difference between the amount billed in relation to a service transaction request and the incremental costs of providing the initial screening and actual processing services for the service transaction request. Under the OEB's direction, the Company has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the Company has deferred these recoveries in accordance with the AP Handbook.

The OEB allows the variances to be deferred which would normally be recorded as revenue for unregulated businesses under IFRS. In absence of rate regulation, revenues in 2018 would have been higher by $17,006 (2019 - higher by $19,368). The deferred balance for unapproved settlement variances continues to be calculated in accordance with the OEB's direction. In its pending COS Application (EB-2020-0043) NBHDL is seeking final disposition of these accounts in the amount of ($181,381), which included cumulative and forecasted carrying charges to April 30, 2021.

v. Deferred Income Taxes

The recovery from, or refund to, customers of future income taxes through future rates is recognized as a regulatory deferral account balance. The Company has recognized a deferred tax asset of $1,426,571 (2019 – $1,325,427) arising from the recognition of regulatory deferral account balances and a corresponding regulatory deferral account credit balance of $1,426,571 (2019 - $1,325,427). The deferred tax asset balance is presented within the total regulatory deferral account balances presented in the statement of financial position.

vi. Other

2020 costs relate to carrying charges on accounts included as regulatory credits, increased OEB cost assessments and incremental revenue related to pole attachment charges and decreased tax expenditures to tax changes.

In 2016, in addition to an increase in the OEB’s internal budget, the OEB also revised its Cost Assessment Model to reflect a change in the methodology used to apportion costs. These changes resulted in a material shift in the allocation of costs. The OEB established a variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment model. The

3. REGULATORY DEFERRAL ACCOUNT BALANCES (CONTINUED)

Company has recorded $30,566 in incremental cost assessment increases in 2020 (2019- $31,474) in the deferral account in accordance with the guidance on the use of the variance account. In its pending COS application (EB-2020-0043), the Company has sought recovery of this regulatory asset in the amount of $173,547, which includes carrying charges forecasted to April 30, 2021.

In September 2018, January 2019, and again in January 2020, the OEB revised its approved pole attachment charges for distributors. The OEB established a variance account for electricity distributors to record the revenue difference between these new rates and previously approved rates. In 2020 NBHDL has recorded ($247,640) as incremental revenue (2019 - $235,866). In its pending COS application (EB-2020-0043), the Company has sought disposition of this regulatory liability in the amount of ($502,695), which includes carrying charges forecasted to April 30, 2021.

In July 2019, the OEB established a variance account to record the effects of the Accelerated Investment Incentive (AII). The AII created new capital cost allowance (CCA) rules that translated to a material difference between taxes built into rates using the OEB Tax Model and taxes that the Company would pay. The OEB also established that this account should reflect the change dating back to the beginning of the AII program start date (November 2018). In 2020, the Company recorded regulatory liabilities of $92,089 (2019 - $177,903). In its pending COS application (EB-2020-0043), the Company has sought disposition of %50 of the 2019 balance included in this regulatory liability in the amount of ($90,344), which includes carrying charges forecasted to April 30, 2021. The Company has further requested to maintain the remaining 50% as income, in accordance with previous OEB treatment of regulatory changes in taxes. This is a pending application and subject to OEB approval.

In March 2020, the OEB issued an accounting order on the establishment of a new deferral account to record the impacts arising from the COVID-19 emergency. The guidance provided was that this account would be used to record the following, but not limited to; costs associated with billing system changes, lost revenues from either load reductions or actions undertaken by utilities, and any other incremental costs. Throughout 2020 this initiative has continued to take shape as the province and utilities reacted to the changing environment with respect to the emergency. As of February 2021, this initiative is still in the consultation phase. As such, further detailed accounting guidance, including policy direction, will be required to be issued by the OEB on key issues in order for utilities to be able to assess the need for, and if necessary, properly make applications for review and disposition.

The Company has included $50,120 in this account for future recovery in relation to incremental costs incurred in response to the COVID-19 pandemic. These costs are primarily related to health and safety related items and the costs associated with enabling remote working arrangements for staff. This amount represents 50% of the total costs in anticipation that these costs must be shared between the Shareholder and customers. These costs would have otherwise been included as expenses in the Statement of Comprehensive Income. The future timing of this application to the OEB, and subsequent approval, are unknown and uncertain and will be determined once the OEB releases guidelines on this initiative.

Expressed in Canadian Dollars

3. Regulatory deferral account balances (continued)

vii. Future Applications

In January 2021, the Company filed its cost of service (COS) application for 2021 rates. As part of this application, the proposed disposition of eligible Group 1 and Group 2 balances for regulatory assets and liabilities as of December 31, 2019, and in some cases, forecasted to December 31, 2020, was included. These balances include carrying charges forecasted to April 30, 2021. The total net amount of the disposition sought is ($419,923) which includes ($68,614) in Group 1 Accounts, ($510,530) in Group 2 Accounts and $159,221 in the remaining other accounts. These dispositions are requested to begin May 1, 2021 and be completed over a one year period ending April 30, 2022.

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. Management continually assesses the likelihood of recovery of regulatory assets and realization of regulatory liabilities. If recovery and realization through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

4. Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated amortization. Costs may include direct material, labour, contracted services, overhead, engineering costs and interest on funds used during construction that are considered applicable to construction. Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as property, plant and equipment since they support the Company’s distribution system reliability. Upon disposal the cost and accumulated amortization of assets are relieved from the respective accounts and any gain or loss is reflected in operations.

Depreciation of property, plant and equipment is recorded in the Statement of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period.

The estimated useful lives are as follows:

Distribution Assets:	
Building and fixtures	30 - 50 years
Substations	40 - 50 years
Poles, towers and fixtures	45 years
Overhead conductor and devices	60 years
Underground conduit and conductor	40 - 50 years
Distribution transformers	40 years
Overhead and underground services	40 – 60 years
Distribution meters	10 - 25 years

4. Property, Plant and Equipment (continued)

General Assets:	
Buildings	25 – 50 years
Office equipment	10 years
Computer equipment	5 years
Transportation equipment	5 - 8 years
Small tools and miscellaneous equipment	10 years
Load management controls	6 years
System supervisory equipment	15 – 20 years

Land is not depreciated.

Expressed in Canadian Dollars

4. Property, Plant and Equipment (continued)

	Electrical Distribution Assets	General Assets	Work in process	Total
Cost				
Balance at January 1, 2019	$ 118,700,881	12,420,536	2,286,359	133,407,776
Additions	6,298,481	799,673	(508,995)	6,589,159
Disposals	(596,504)	(89,410)	(442,669)	(1,128,583)
Balance at December 31, 2019	124,402,858	13,130,799	1,334,695	138,868,352
Balance at January 1, 2020	124,402,858	13,130,799	1,334,695	138,868,352
Additions	5,569,113	444,709	171,008	6,184,830
Disposals / Reallocation	(392,197)	(32,462)	(6,051)	(430,710)
Balance at December 31, 2020	129,579,774	13,543,046	1,499,652	144,622,472
Depreciation and impairment losses				
Balance at January 1, 2019	54,958,535	9,147,609	-	64,106,144
Depreciation for the year	2,385,235	596,606	-	2,981,841
Disposals	(397,873)	(89,411)	-	(487,284)
Balance at December 31, 2019	$ 56,945,897	$ 9,654,804	$ -	$ 66,600,701
Balance at January 1, 2020	56,945,897	9,654,804	-	66,600,701
Depreciation for the year	2,535,449	623,475	-	3,158,924
Disposals	(349,582)	(32,462)	-	(382,044)
Balance at December 31, 2020	$ 59,131,764	$ 10,245,817	$ -	$ 69,377,581
Carrying amounts:				
At December 31, 2019	$ 67,456,961	$ 3,475,995	$ 1,334,695	$ 72,267,651
At December 31, 2020	$ 70,448,010	$ 3,297,229	$ 1,499,652	$ 75,244,891

Expressed in Canadian Dollars

5. Revenue Recognition

As a licensed distributor, the Company 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 Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. The Company has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Revenues from the sale and distribution of electricity is recognized over time on an accrual basis upon delivery of electricity, including unbilled revenues accrued in respect of electricity delivered but not yet billed. Sale and distribution of electricity revenue is comprised of customer billings for provincial electricity costs and distribution service charges. Customer billings for distribution service charges are recorded based on meter readings, and are generally due within 30 days of the billing date.

Other revenues, which include revenues from pole use rental, collection charges and other miscellaneous revenues are recognized at the time services are provided. Where the Company has an ongoing obligation to provide services, revenues are recognized as the service is performed and amounts billed in advance are recognized as deferred revenue.

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions vary by project and are based on the criteria set forth in the Distribution System Code. Since the contributions will provide customers with ongoing access to the supply of electricity, these contributions are classified as contributions in aid of construction, recognized when they are billed and are amortized as revenue on a straight-line basis over the useful life of the constructed or contributed asset.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The continuity of deferred contributions in aid of construction is as follows:

	December 31 2020	December 31 2019
Deferred contributions, net, beginning of year	$ 3,890,009	$ 3,500,338
Contributions in aid of construction received	558,748	483,042
Contributions in aid of construction recognized as distribution revenue	(104,192)	(93,371)
Deferred contributions, net, end of year	$ 4,344,565	$ 3,890,009

All contributions in aid of construction are cash contributions and are recognized when billed. There have not been any contributions of property plant and equipment.

Expressed in Canadian Dollars

6. INVESTMENT IN ASSOCIATE

The Company has an equity interest in Ecobility; a company owned by five different shareholders all of whom own, operate, or are affiliated with, a local distribution company. The company operates out of Sudbury and Toronto and facilitates the management and delivery of Provincial conservation programs across the service territories of each owner and other locations throughout the Province.

Of the 143,860 shares issued, the company owned 16.66% at year end. Of the five voting shares, the Company holds one. This equity interest is measured on the balance sheet using the equity method of accounting. The Company's share of preliminary net earnings of $905,707 for the year is $236,851 (2019 - $605,148). Dividends recorded against the investment throughout the year totaled $166,845 (2019 - $245,028). The investee had total assets of $5,395,475 and shareholders' equity of $2,763,077 as at December 31, 2020.

7. ACCOUNTS RECEIVABLE, UNBILLED REVENUE AND CUSTOMER DEPOSITS

	December 31 2020	December 31 2019
Accounts receivable due from related parties	$ 1,548,644	$ 1,454,801
Short term advances to related parties	-	-
Customer accounts receivable	7,099,900	8,542,984
Loss allowance	(186,376)	(131,556)
Total accounts receivable	$ 8,462,168	$ 9,866,229

a) Recognition and initial measurement

The Company initially recognizes accounts receivable on the date on which they are originated and recognizes unbilled service revenue on the date on which the Company delivers the electricity but has not yet billed the customer. Similar to customer billings, unbilled revenue for distribution service charges are recorded based on meter readings. Accounts receivable and unbilled service revenue are initially measured at fair value.

b) Classification and subsequent measurement

Accounts receivable and unbilled service revenue are classified and subsequently measured at amortized cost because they meet the solely payments of principal and interest criterion and are held within a business model whose objective is to hold financial assets in order to collect contractual cash flows. The carrying amount is reduced through the use of a loss allowance and the amount of the related loss allowance is recognized in profit or loss. Subsequent recoveries of receivables and unbilled service revenue previously provisioned are credited to profit or loss.

c) Fair value measurement

Due to its short-term nature, the carrying amounts of accounts receivable and unbilled service revenue approximates their fair value.

7. ACCOUNTS RECEIVABLE, UNBILLED REVENUE AND CUSTOMER DEPOSITS (CONTINUED)

d) Credit risk

Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as deposits, which are reported separately from the Company's own cash and cash equivalents. Deposits to be refunded to customers within the next fiscal year are classified as a current liability. Interest rates paid on customer deposits are based on the Bank of Canada's prime business rate less 2%.

Due to its short-term nature, the carrying amount of the accounts receivable due from related parties and other accounts receivable approximates its fair value. Unbilled service revenue reflects the electricity delivered but not yet billed to customers. Customer billings generally occur within 30 days of delivery. The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Company has 24,492 customers, the majority of which are residential. The Company considers an account receivable to be in default when the customer is unlikely to pay its credit obligations in full, without recourse by the Company, such as realizing security (if any is held). Accounts are past-due (in default) when the customers have failed to make the contractually requirements payments when due, which is generally within 30 days of the billing date.

Historically, the Company considered an account receivable to be credit-impaired when the customer had amounts more than 90 days past the billing date. In determining the allowance for doubtful accounts for 2020, the Company reviewed commercial and industrial customer accounts on an individual basis and considered historical loss, payment experience, payment arrangements and economic conditions in light of COVID-19, as well as the aging and arrears status of the account in the determination of impairment. For residential accounts, the Company took a similar approach on an aggregate level as well as undertaking an overall analysis of historical write-offs, provisions, subsequent recoveries and payment patterns to determine the reasonability of the impairment. The Company considers the current economic and credit conditions to determine the loss allowance of its accounts receivable. Given the high degree of uncertainty caused by the COVID-19 outbreak, the estimates and judgments made by management in the preparation of the expected credit loss allowance are subject to a high degree of estimation uncertainty. The Company continues to actively monitor its exposure to credit risk.

Expressed in Canadian Dollars

7. ACCOUNTS RECEIVABLE, UNBILLED REVENUE AND CUSTOMER DEPOSITS (CONTINUED)

The following table provides information about the exposure to credit risk for accounts receivable by level of delinquency.

	31-Dec-20			31-Dec-19		
	Gross	Loss Allowance	Net	Gross	Loss Allowance	Net
Less than 30 days past billing date	$5,369,538	$20,059	$5,349,479	$5,610,098	$5,332	$5,604,766
30-60 days past billing date	423,573	18,356	405,217	315,210	7,511	307,699
61-90 days past billing date	104,234	16,636	87,598	103,967	6,321	97,646
More than 90 days past billing date	236,244	131,325	104,919	112,391	112,391	-
	$6,133,589	$186,376	$5,947,213	$6,141,666	$131,555	$6,010,111

The following tables present a summary of the activity related to the Company’s accounts receivable loss allowances.

	December 31 2020	December 31 2019
Balance January 1	$ 131,556	$ 114,532
Additions (Provision for credit loss)	113,333	121,132
Accounts Written off, net of recoveries	(58,513)	(104,108)
Other	-	-
Balance, December 31	$ 186,376	$ 131,556

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

Expressed in Canadian Dollars

7. ACCOUNTS RECEIVABLE, UNBILLED REVENUE AND CUSTOMER DEPOSITS (CONTINUED)

Customer deposits represents cash deposits from electricity distribution customers and retailers. Deposits from electricity distribution customers are refundable to customers demonstrating an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

	December 31 2020	December 31 2019
Customer deposits – current	$ 59,114	$ 94,281
Customer deposits – long-term	626,741	732,674
Total customer deposits	$ 685,855	$ 826,955

a) Recognition and initial measurement

The Company initially recognizes customer deposits on the date on which the Company received the deposit. Customer deposits are initially measured at fair value.

b) Classification and subsequent measurement

Customer deposits are classified and subsequently measured at amortized cost, using the effective interest rate method.

c) Fair value measurement

The fair value of customer deposits approximates their carrying amounts taking into account interest accrued on the outstanding balance.

8. PAYMENTS IN LIEU OF TAXES PAYABLE

The Company is a Municipal Electricity Utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the Company is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Under the Electricity Act, 1998, the Company is required to make payments in lieu of corporate income taxes each year to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001. These payments are calculated in accordance with the rules for computing taxable income and other relevant amounts contained in the Income Tax Act (Canada) and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. PILs expense comprises of current and deferred tax. Current tax and deferred tax are recognized in comprehensive income except to the extent that it relates to items recognized directly in equity or regulatory deferral account balances.

Significant judgment is required in determining the provision for PILs. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Company recognizes liabilities for anticipated tax audit issues based on the Company's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions

Expressed in Canadian Dollars

8. PAYMENTS IN LIEU OF TAXES PAYABLE (CONTINUED)

in the period in which such determination is made.

Significant components of the payments in lieu of taxes expense are as follows:

a. Expense

The Company's provision for PILs is calculated as follows:

	2020	2019
Income before provision for payment in lieu of income taxes	$ 169,457	$ 2,498,594
Regulatory assets/liabilities added (deducted) for tax purposes	421,363	(274,885)
Net change in reserves (EFB)	13,243	15,675
Capital cost allowance (greater than) less than amortization expense	(2,419,738)	(1,807,071)
Other items	(332,017)	(741,403)
Unrealized (gain) loss	2,102,924	681,401
(Gain) loss on disposal of assets	44,768	90,272
Income (loss) for tax purposes	-	462,583
Statutory Canadian federal and provincial tax rate	26.50%	26.50%
Provision for PILs (recovery)	$ NIL	$ 122,584
Total current tax provision	$ NIL	$ 122,584

b. Deferred Taxes

Components of deferred taxes are as follows:

	2020	2019
Property, plant and equipment	$ (459,360)	$ 49,549
SWAP Gain / Loss	421,190	-
Employee future benefits	1,279,439	1,202,237
Regulatory Assets / Liabilities	185,302	73,641
Total deferred tax assets	$ 1,426,571	$ 1,325,427

9. Employee Future Benefits

Employee future benefits other than pension provided by the Company include medical and insurance benefits. These benefit plans provide benefits to certain employees when they are no longer providing active service.

The cost of these benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long-term nature, the cost of these benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date.

The calculation is performed by a qualified actuary using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. The valuation is performed every third year or when there are significant changes to workforce. A full valuation was performed in 2019.

Remeasurements of the defined benefit obligation are recognized directly within equity in other comprehensive income. The remeasurements include actuarial gains and losses.

Service costs are recognized in the Statement of Comprehensive Income in operating expenses, and include current and past service costs as well as gains and losses on curtailments.

Net interest expense is recognized on the Statement of Comprehensive Income in finance costs, and is calculated by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the balance of the net defined benefit obligation, considering the effects of benefit payments during the period. Gains or losses arising from changes to defined benefits or plan curtailment are recognized immediately in the Statement of Comprehensive Income. Settlements of defined benefit plans are recognized in the period in which the settlement occurs.

The plan is exposed to a number of risks, including:

Interest rate risk: decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation.

Longevity risk: changes in the estimation of mortality rates of current and former employees.

Health care cost risk: increases in cost of providing health, dental and life insurance benefits.

Expressed in Canadian Dollars

9. Employee Future Benefits (continued)

The Company has a defined benefit life insurance and health care plan covering all active employees and most retirees. Information about the Company's defined benefit life insurance and health care plan is as follows:

	2020	2019
Prepaid benefit liability, beginning of year	$ 4,536,742	$ 4,256,659
Expense for the year	270,702	275,841
Benefits paid during the year	(257,459)	(260,166)
Actuarial gains/losses recognized	278,086	264,408
Prepaid benefit liability, end of year	$ 4,828,071	$ 4,536,742
Fair value of plan assets	$NIL	$NIL

Included in wages and employee benefits and finance costs respectively, is a net benefit expense as follows:

	2020	2019
Total service cost of the plan for the year	$ 140,886	$ 121,320
Interest on average liabilities	129,816	154,521
Total Expense for the year	$ 270,702	$ 275,841

The main actuarial assumptions employed for the valuations are based on the full actuarial report performed in 2019. In 2020, the Company hired an outside consulting firm to update the actuarial valuation report based on the changes noted below, including an update of employee and retiree status.

Expected average remaining service life of active employees 13 years.

a. General Inflation / Salary Levels

b. In 2019, the actuarial report was based on salary scale assumption based on the Corporation's management of 2% per annum up to 2022 and 3% per annum for 2023 onwards. This change reflected the Corporation's bargaining agreements and consideration for increases in the salary scale in the long term. As such, in 2020 there was no inflation rate used in the valuation. Interest (Discount) Rate

   The obligation at year end, of the present value of future liabilities and the expense for the year ended, were determined using a discount rate of 2.5% (2019- 3.1%). The discount rate for 2020 reflects the assumed long-term yield on high quality bonds as at December 31, 2020 (most recent valuation date).

c. Medical Costs

   Medical costs reflect cost increase assumptions from the full valuation in 2019 and continue to be assumed to increase 4.20% from 2020-2024, 5.3% from 2025-2034, 4.6% from 2035-2039, and 4% thereafter.

9. EMPLOYEE FUTURE BENEFITS (CONTINUED)

d. Dental Costs

Dental costs reflect cost increase assumptions from the full valuation in 2019 and continue to be assumed to increase at 4.5% from 2020-2024, 5.60% from 2025-2029, 5.30% from 2030-2034, 4.60% from 2035-2039 and 4% thereafter.

The Company's sick accrual is included above in the amount of $237,900 (2019 - $220,400) and is the accumulation of non-vested sick leave benefits under IAS 19 standards for financial reporting purposes. The Company hired an outside consulting firm to assess the future payments to be made as a result of the Company's employees' sick leave bank hours in 2020. The discount rate used in 2020 was 2.50% (2019 – 3.10%). The Future general salary and wage levels were assumed to increase at 2.0% per annum up to 2022 and 3.0% per annum thereafter.

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities.

10. RELATED PARTY TRANSACTIONS

The Company provides administrative and other services to an affiliated company, North Bay Hydro Services Inc. ("Services"). Electrical energy is also sold to Services at the same prices and terms as other electricity customers consuming equivalent amounts of electricity.

The Company also provides administrative services to an affiliated company, Espanola Regional Hydro Distribution Company ("ERHDC").

During the current year, the Company provided inter-company loans to both Services and ERHDC in the form of Promissory Notes.

The Corporation of the City of North Bay (the "City") is the 100% owner of North Bay Hydro Holdings Inc. which is the parent company of North Bay Hydro Distribution Limited, North Bay Hydro Services Inc. and Espanola Regional Hydro Distribution Corporation (amalgamated with North Bay (Espanola) Acquisition Inc. October 1, 2019).

Electrical energy is sold to the City at the same prices and terms as other electricity customers consuming equivalent amounts of electricity. Streetlight maintenance services are provided at rates determined in relation to other service providers. Other construction services are provided at cost.

The loan to Services is in the amount of $200,000 and the interest rate on this facility is equal to the prime rate as defined by the Bank of Canada, and cross referenced against TD Bank's rate, currently at 2.45%. Interest only payments were made in 2020 and will continue until the loan is due in 2025, however, Services may prepay any or all of the principal at any time. Interest is calculated, accrued and paid for monthly. The loan balance at December 31, 2020 was $200,000.

The Company has three inter-company loan arrangements with ERHDC. The interest rate on all three facilities is equal to the prime rate as defined by the Bank of Canada, and cross referenced against TD Bank's rate,

10. RELATED PARTY TRANSACTIONS (CONTINUED)

currently at 2.45%. Interest is calculated, and accrued, monthly. Promissory notes are in place for the original $200,000 deposit that was made in relation to the acquisition of ERHDC by NBEAI and a second loan of $265,000 to cover interest payments on a loan that ERHDC has with TD Bank. The Company has also provided ERHDC with a credit facility with a maximum draw amount of $1,100,000 to cover the costs associated with ERHDC's 2021 COS application. At the time of these statements, the total costs of the application are expected to be approximately $572,000, and the loan carries a value of $218,558 as of December 31, 2020.

Expressed in Canadian Dollars

10. Related Party Transactions (continued)

The following tables summarize the transactions that occurred between North Bay Hydro Distribution Limited and its affiliates.

	Sale of Goods		Purchase of Goods		Amounts owed to (from)	
	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019	Year Ended December 31, 2020	Year Ended December 31, 2019
NBHS						
Contract services and other	$ 397,199	$ 441,308	$ -	$ -	$ -	$ -
Electricity Sales	306,822	142,021	-	-	-	-
Contributed Capital Costs	30,592	155,963	-	-	-	-
Other Revenue	1,173	-	117,165	245,484	-	-
Total statement of earnings and retained earnings	$ 735,786	$ 739,292	$ 117,165	$ 245,484	$ -	$ -
Accounts receivable	$ -	$ -	$ -	$ -	$ (896,259)	$ (794,333)
Accounts payable	-	-	-	-	470,466	380,023
Loan Receivable	-	-	-	-	(200,000)	-
Total statement of financial position	$ -	$ -	$ -	$ -	$ (625,793)	$ (414,310)
ERHDC						
Accounts Receivable	$ -	$ -	$ -	$ -	$ (377,703)	$ (343,451)
Loan Receivable	-	-	-	-	(704,196)	(207,900)
NBEAI Total	$ -	$ -	$ -	$ -	$ (1,081,899)	$ (551,351)
Hydro Holdings						
Administration fees	$ -	$ -	$ 12,000	$ 12,000	$ -	$ -
Holdco total	$ -	$ -	$ 12,000	$ 12,000	$ -	$ -
City of North Bay						
Electrical energy sales	$ 3,108,795	$ 3,519,935	$ -	$ -	$ -	$ -
Construction activity sales	6,669	73,563	-	-	-	-
Street light maintenance	4,587	7,703	-	-	-	-
Fuel / water / other	-	-	188,424	146,785	-	-
Total statement of earnings and retained earnings	$ 3,120,051	$ 3,601,201	$ 188,424	$ 146,785	$ -	$ -
Accounts receivable	-	-	-	-	$ (274,682)	$ (317,017)
Accounts payable	-	-	-	-	16,063	60,790
Total statement of financial position	$ -	$ -	$ -	$ -	$ (258,619)	$ (256,227)

Expressed in Canadian Dollars

11. LOAN GUARANTEE

The company has a financial loan guarantee to a related company under common control; the guarantee covers the amount outstanding to two commercial lenders. The amount of debt outstanding, related to this financial guarantee at year end, was $10,522,693. The guarantee would be triggered if the related party defaulted on its financial obligations, primarily with respect to monthly debt payments. There is no collateral held for this guarantee and no fees were charged during the year in relation to this financial guarantee.

12. INVENTORY

Cost of inventories comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory on the basis of weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory. Inventory is recognized at the lower of cost and net realizable value. The amount of inventories consumed by the Company and recognized as an expense during 2020 was $78,729 (2019 - $110,895).

Inventory consists of parts, supplies and materials held for future capital expansion or maintenance and are valued at the lower of cost, determined by the weighted average method, and replacement cost.

13. SHARE CAPITAL

Authorized:

Unlimited Common shares

The issued share capital is as follows:

	2020	2019
1,001 Common Shares	$ 19,511,601	$ 19,511,601

Expressed in Canadian Dollars

14. OPERATING EXPENSES BY NATURE

	2020	2019
Repairs and maintenance	$ 1,385,294	$ 1,267,626
Staff costs	4,428,416	4,131,417
General administration, overhead and recoveries	768,248	1,131,629
Bad debts	113,333	121,132
Property taxes	92,401	87,960
	$ 6,787,692	$ 6,739,764

Management Compensation

During the year the company compensated its senior management group $1,196,497 (2019 - $1,168,945), including salaries and benefits.

15. FINANCE INCOME AND FINANCE COST

	2020	2019
Finance Income:		
Interest income on receivables	$ 86,939	$ 186,699
Interest income on bank deposits	120,085	205,767
	$ 207,024	$ 392,466
Finance Cost:		
Interest on long-term debt	$ 1,052,576	$ 1,050,844
Net interest on employee future benefits	129,816	154,521
	$1,182,392	$1,205,365

16. LONG-TERM DEBT

The Company negotiated a loan with the Ontario Infrastructure Projects Corporation to provide funding for the Smart Meter project. The loan is a 10 year serial loan at an interest rate of 3.90% calculated on a semi-annual basis. The loan will be repaid in 120 monthly installments which will include both principal and interest. The loan balance at the end of the year was $116,667 (2019 - $466,667), of which is repayable within one year.

The Company's agreement with the Ontario Infrastructure Projects Corporation requires a debt service coverage ratio of 1.3 or higher. As at December 31, 2020 the Company was not in compliance with these covenants. The full amount of this loan is classified as a current liability and the loan will be paid in full April 2021.

Expressed in Canadian Dollars

16. LONG-TERM DEBT (CONTINUED)

The Company has seven term loans in the amounts of $4,000,000, $4,500,000, $5,500,000, two loans of $5,000,000, and two loans valued at $6,000,000 loans with a Canadian Financial Institution and has entered into interest rate derivative agreements to manage the volatility of interest rates on long-term debt for each. All of these loans are to be repaid over 120 months with combined repayments of $340,209 per month principal and interest having fixed rates at 3.095%,3.55%, 2.45%, 2.36%, 2.88%,2.37%, and 1.56% respectively.

The Company entered into a term loan in the amount of $19,500,000 to replace the existing loan agreement with the City of North Bay. This loan is to be repaid over 240 months with repayments of $103,331 per month principal and interest at a rate of 2.5%.

The fair value of these loans are $42,286,799 (2019- $40,438,654) which is estimated by obtaining market-to-market quotes from the Toronto Dominion Bank resulting in an interest rate swap mark-to-market financial liability (asset) of $1,589,397 (2019 – ($513,527)). The quoted prices generally reflect the estimated amount that the Company would pay (receive) to settle these agreements at the statement of financial position date.

The Company must maintain Debt Service Coverage (DSC) ratio of not less than 1.20:1 on to remain in compliance with outstanding debt obligations.

Estimated principal repayments required to settle long term obligations are as follows (excludes interest rate swap mark-to-market adjustment):

2021	$ 4,437,830
2022	4,436,748
2023	4,550,543
2024	4,587,679
2025	4,198,009
Thereafter	20,075,990
	$ 42,286,799

The interest rates on these financial instruments are fixed and therefore the Company is not exposed to fluctuations in short-term interest rates in relation to these debts.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company has a planning and budgeting process in place to help determine the funds required to support the Company's normal operating requirements on an on-going basis. The Company strives to maintain a liquidity level that allows for sufficient funds to meet operational requirements so that obligations can be met as they become due.

16. LONG-TERM DEBT (CONTINUED)

The following table sets out the contractual maturities (representing undiscounted contractual cash flows) of financial liabilities:

December 31, 2019	60 days	< 1 year	1 – 5 years	> 5 years
Accounts payable	$11,740,444	$ -	$ -	$ -
Loans	622,810	3,156,387	16,154,324	20,151,646
	$12,363,254	$3,156,387	$16,154,324	$20,151,646

December 31, 2020	60 days	< 1 year	1 – 5 years	> 5 years
Accounts payable	$9,587,989	$ -	$ -	$ -
Loans	769,376	3,669,628	21,452,915	16,391,137
	$10,357,365	$3,669,628	$21,452,915	$16,391,137

17. CONTINGENCIES

The Company belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2020, the Company has not been made aware of any assessments for losses.

18. COMMITMENTS

On October 9, 2009 the Company entered into a 15 year contract with Sensus Metering Systems Inc. to maintain and further develop the AMI system that meets the MEU functional specifications related to the Smart Meter Project. The contract contains 3 renewal terms of 5 years each. The Company elected to have the monthly fees billed in US dollars, instead of having the currency rate set on an annual basis in October of each year. Termination penalties apply if the Company cancels the contract without cause, the related fees are based on a sliding scale for the year this takes place and the fees associated with the service option selected. Annual fees in the amount of approximately $206,000 are expected to be incurred under this contract, however can fluctuate based on several factors including performance. This contract exposes the Company to currency risk with fluctuations in currency prices when it purchases US dollars to meet the payable commitments.

19. Credit Facility / Letters of Credit

The Company has an authorized line of credit under a credit facility agreement with a Canadian chartered bank. The credit limit permitted under this agreement is $7,000,000. At year end the Company had drawn $Nil (2019 - $Nil) under this facility.

The Company has a $3.6 million letter of credit with its bank provided to the IESO to secure the Company's hydro purchase obligations. The Company has provided its financial institution with a General Security Agreement as security for this obligation.

The Company's general banking agreement which encompasses the line of credit, revolving term facility and the letter of credit contains financial covenants which include a debt to capital ratio lower than 60% and a debt service coverage ratio of not less than 1:2 and positive free cash flow. Distributions in excess of free cash flow are permitted when financed by cash on hand. As at December 31, 2020 the Company was in compliance with these covenants.

The Company strives to maintain a liquidity level that allows for sufficient funds to meet operational requirements so that obligations can be met as they become due while minimizing interest expense. The Company monitors cash balances regularly and has access to short-term borrowings, should they be required, under its credit facility agreement. If the Company were to utilize this facility it would be exposed to fluctuations in short-term interest rates.

20. Pension Agreements

The Company makes contributions to the OMERS, which is a multi-employer pension plan, on behalf of all full-time members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to almost half a million active and retired members and approximately 1,000 employers.

Each year an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2020. The results of this valuation disclosed total actuarial liabilities of $113,055 million in respect of benefits accrued for service with actuarial assets at that date of $109,844 million indicating actuarial deficit of $3,211 million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the Company does not recognize any share of the OMERS pension surplus or deficit. The amount contributed to OMERS for 2020 was $406,921 (2019 - $430,516).

21. CAPITAL DISCLOSURES

THE COMPANY CONSIDERS ITS CAPITAL TO COMPRISE ITS COMMON SHARE CAPITAL, RETAINED EARNINGS, AND LONG-TERM DEBT.

In managing its capital, the Company's primary objective is to ensure its continued ability to provide a consistent return for its equity shareholders through a combination of capital growth and through the payment of periodic dividends to its common shareholders. The Company also seeks to ensure that access to funding is available in order to maintain and improve the equipment used in operations and maintain financial ratios within the recommended guidelines as prescribed by the OEB. In order to achieve these objectives, the Company develops detailed annual operating budgets and seeks to maintain distribution revenue levels and control costs to enable the Company to meet its working capital requirements and strategic investment needs. In making decisions to adjust its capital structure to achieve these objectives, the Company considers both its short-term position and long-term operational and strategic objectives.

As at December 31, 2020 the Company is party to debt agreements that contain various covenants and is restricted from offering loans or paying dividends that would cause a violation of those covenants.

22. STANDARDS, AMENDMENTS AND INTERPRETATIONS NOT YET EFFECTIVE

There are no other standards, interpretations or amendments issued, but not yet effective that the Company anticipates may have a material effect on the financial statements once adopted.

23. UNCERTAINTY DUE TO COVID-19

The assessment of the duration and severity of the developments related to the COVID-19 pandemic continue to be subject to significant uncertainty. The company has developed guidelines for its workforce that align with the Provincial Framework and prioritize the safety of employees, customers, and the public. These guidelines enable the company to pivot to appropriate work protections depending on the various orders that the local and provincial health authorities issue. The local and provincial directives have the ability to halt all non-essential work; the company provides an essential service to the community and work in the public domain continues under the above-mentioned guidelines and administrative staff have been transitioned to a work from home approach.

The pandemic has affected customers in different ways. Residential consumption has increased and the commercial and industrial customer base has seen a decrease in demand on the system, however, the continued impact of the pandemic on customer energy needs is difficult to predict and quantify. The pandemic can affect supply chains (delays, constraints, cost increases) and the collectability of accounts receivable; these areas of the business continue to be monitored and managed closely by the company, however, they are subject to continued uncertainty. At this time, the future impact of COVID-19 on the entity cannot be known with certainty.

Espanola Regional Hydro Distribution Corporation

Financial Statements

Three Month Period from October 1, 2019 to December 31, 2019

INDEPENDENT AUDITOR'S REPORT

To: The Shareholder of
Espanola Regional Hydro Distribution Corporation

Opinion
We have audited the financial statements of **Espanola Regional Hydro Distribution Corporation**, which comprise the statement of financial position as at **December 31, 2019**, and the statements of comprehensive loss, retained earnings (deficit) and accumulated other comprehensive earnings (loss), and cash flows for the three month period from October 1, 2019 to December 31, 2019, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at **December 31, 2019**, and the results of its operations and its cash flows for the three month period 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 Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical 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.

Emphasis of Matter
We draw attention to note 21 to these financial statements, which describes that Espanola Regional Hydro Distribution Corporation, along with Espanola Regional Hydro Holdings Corporation, were acquired by North Bay (Espanola) Acquisition Inc. on October 1, 2019 and the three corporations were immediately amalgamated, also on October 1, 2019, with the amalgamated corporation continuing to carry on operations as Espanola Regional Hydro Distribution Corporation.

We also draw your attention to note 22 to these financial statements which describes the effect of the above noted transactions on the comparative figures presented in these financial statements.

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 Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern

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and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation’s financial reporting process.

Auditor's 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 auditor’s 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 these 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 Corporation'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 Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's 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 auditor's report. However, future events or conditions may cause the Corporation 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.

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INDEPENDENT AUDITOR'S REPORT, continued

We 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.

Freelandt Caldwell Reilly LLP

FREELANDT CALDWELL REILLY LLP

Chartered Professional Accountants
Licensed Public Accountants

Sudbury, Ontario
April 16, 2020

Espanola Regional Hydro Distribution Corporation

Statement of Financial Position

December 31, 2019 with comparative figures for September 30, 2019

	December 31 2019	September 30 2019 (note 22)
Assets		
Current		
Cash	$ 317,887	$ 375,296
Accounts receivable (note 4)	1,226,204	1,250,255
Unbilled revenue - energy sales	791,739	282,042
Unbilled revenue - distribution	156,681	114,319
Inventory	48,049	44,205
Prepaid expenses	118,235	141,913
Payment in lieu of taxes	1,816	1,814
	2,660,611	2,209,844
Advances to corporate shareholder	100	-
Property, plant and equipment (note 5)	5,145,115	5,106,006
Goodwill	3,322,007	-
Total assets	11,127,833	7,315,850
Regulatory assets (note 6)	2,697,028	2,775,259
Total assets and regulatory assets	$ 13,824,861	$ 10,091,109

Approved on behalf of the Board of Directors:

Director ________________________

Director ________________________

Espanola Regional Hydro Distribution Corporation

Statement of Financial Position

December 31, 2019 with comparative figures for September 30, 2019

	December 31 2019	September 30 2019 (note 22)
Liabilities and shareholders' equity (deficiency)		
Current		
Operating loan (note 7)	$ 235,000	$ -
Accounts payable and accrued liabilities	233,852	870,865
Payable for energy purchases	1,854,606	1,178,732
Advances from related company (note 8)	551,351	-
Current portion of long-term obligations	89,370	88,608
	2,964,179	2,138,205
Customer deposits	220,351	223,680
Deferred revenue	104,799	114,098
Payment in lieu of deferred taxes (note 9)	167,980	50,998
Contributions in aid of construction (note 10)	345,940	348,367
Employee future benefits (note 11)	98,543	98,197
Long-term obligations (note 12)	9,818,431	2,004,871
Notes payable (note 13)	-	1,524,511
	13,720,223	6,502,927
Shareholders' equity (deficiency)		
Share capital (note 14)	100	2,281,000
Retained earnings (deficit)	(462,820)	876,190
Accumulated other comprehensive earnings (loss)	-	(11,471)
	(462,720)	3,145,719
Total liabilities and shareholders' equity (deficiency)	13,257,503	9,648,646
Regulatory liabilities (note 6)	567,358	442,463
Total liabilities, shareholder's equity (deficiency) and regulatory liabilities	$ 13,824,861	$ 10,091,109

Commitments (note 18)

Espanola Regional Hydro Distribution Corporation

Statement of Comprehensive Loss
Three month period from October 1, 2019 to December 31, 2019
with comparative figures for the nine month period from January 1, 2019 to September 30, 2019

	December 31, 2019 (3 months)	September 30, 2019 (9 months) (note 22)
Revenue		
Energy sales	$ 2,363,438	$ 4,943,711
Distribution	429,486	1,212,692
	2,792,924	6,156,403
Cost of Energy	2,043,330	5,171,386
Gross Profit	749,594	985,017
Operating expenses (note 15)		
General and administration	159,978	329,278
Billing and collecting	87,360	362,763
Distribution - operations	95,436	335,519
Distribution - maintenance	68,915	223,910
Depreciation	41,801	127,061
	453,490	1,378,531
Earnings (loss) before other income (expense) and payment in lieu of taxes	296,104	(393,514)
Other income (expense)		
Interest	26,048	19,481
Labour, rental and other charges	21,702	118,597
Amortization of contributions in aid of construction	2,527	7,581
Interest on long-term obligations and notes payable	(73,810)	(109,148)
Interest rate swap mark-to-market adjustment (note 12)	(46,660)	-
	(70,193)	36,511
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	225,911	(357,003)
Payments in lieu of taxes (recovery) (note 9)		
Current	-	(2,025)
Deferred	116,982	(51,934)
	116,982	(53,959)
Net earnings (loss) before change in regulatory asset and liability balances and other comprehensive earnings (loss)	108,929	(303,044)
Change in regulatory assets and liabilities (note 6)		
Change in regulatory asset and liability account balances related to profit and loss	(320,108)	227,675
Change in regulatory asset account balance related to payment in lieu of deferred taxes	116,982	(51,934)
	(203,126)	175,741
Net loss before other comprehensive loss	(94,197)	(127,303)
Other comprehensive loss		
Remeasurement of employee future benefits liability, net of tax	-	(12,469)
Net comprehensive loss	$ (94,197)	$ (139,772)

Espanola Regional Hydro Distribution Corporation

Statement of Retained Earnings (deficit) and Accumulated Other Comprehensive Earnings (Loss)
Three month period from October 1, 2019 to September 30, 2019
with comparative figures for nine month period from January 1, 2019 to September 30, 2019

	Share capital	Retained earnings (deficit)	Accumulated other comprehensive earnings (loss)	Total
Balance at September 30, 2019, as originally stated (note 22)	$ 2,281,000	876,190	(11,471)	$ 3,145,719
Amalgamation adjustment (note 22)	(2,280,900)	(1,244,813)	11,471	(3,514,242)
Balance at October 1, 2019, as adjusted	100	(368,623)	-	(368,523)
Net earnings (loss) before other comprehensive loss (3 months)	-	(94,197)	-	(94,197)
Other comprehensive loss	-	-	-	-
Balance at December 31, 2019	100	(462,820)	-	(462,720)
Balance at December 31, 2018	2,281,000	1,003,493	998	3,285,491
Net earnings (loss) before other comprehensive loss (nine months)	-	(127,303)	-	(127,303)
Other comprehensive loss	-	-	(12,469)	(12,469)
Balance at September 30, 2019 (note 22)	$ 2,281,000	876,190	(11,471)	$ 3,145,719

Espanola Regional Hydro Distribution Corporation
Cash Flows Statement
Three month period from October 1, 2019 to December 31, 2019
with comparative figures for the nine month period from January 1 2019 to September 30, 2019

	December 31, 2019 (3 months)	September 30, 2019 (9 months) (note 22)
Cash flows from operating activities		
Net loss	$ (94,197)	$ (127,303)
Adjustments to reconcile earnings to cash provided by (used in) operations:		
Depreciation	48,621	147,422
Amortization of contributions in aid of construction	(2,527)	(7,581)
Provision for payment in lieu of deferred taxes	116,982	(51,934)
Provision for payment in lieu of taxes	-	(2,025)
Interest rate swap mark-to-market adjustment	46,660	-
	115,539	(41,421)
Change in non-cash working capital items (note 16)	(840,594)	231,977
	(725,055)	190,556
Cash flows from investing activities		
Purchase of property, plant and equipment	(87,730)	(373,213)
Regulatory assets	78,231	(128,815)
	(9,499)	(502,028)
Cash flows from financing activities		
Operating loan	235,000	-
Advances from related company	351,351	-
Customer deposits	(3,329)	13,318
Deferred revenue	(9,299)	(23,159)
Regulatory liabilities	124,895	(46,926)
Contributions in aid of construction	100	39,190
Employee future benefits	346	1,341
Repayment of long-term obligations	(26,317)	(64,492)
	672,747	(80,728)
Decrease in cash	(61,807)	(392,200)
Cash, beginning of period	379,694	767,496
Cash, end of period	$ 317,887	$ 375,296

1. **Nature of operations**

Espanola Regional Hydro Distribution Corporation was created on October 1, 2019 by the amalgamation of North Bay (Espanola) Acquisition Inc., Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation. The corporation is required in accordance with the Electricity Act, 1998, Ontario (the EA), is a wholly owned subsidiary of North Bay Hydro Holdings Limited, and was created for the purpose of providing regulated electricity distribution services to customers in the Town of Espanola and the Township of Sables-Spanish Rivers from its head office located at 598 Second Street, Espanola Ontario, Canada.

The Corporation and other electricity distributors purchase their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recover the costs of electricity and certain other costs from customers under the authority of the Ontario Energy Board (the OEB) Act, 1998.

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and the filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility for ensuring that electricity distribution companies fulfil their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry may affect distribution rates and the permitted recovery or settlement or the timing of recovery or settlement of certain regulatory assets and liabilities.

2. **Significant accounting policies**

These financial statements are prepared using International Financial Reporting Standards applying the accounting policies set out below on a consistent basis in all periods presented in these financial statement. The significant policies are detailed as follows:

(a) **Statement of compliance and basis of measurement**

These financial statements are the representation of the Corporation`s management and are prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB). The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2019. The Corporation has adopted the requirements of IFRS 14 - Regulatory Deferral Accounts, which permits the Corporation to account for regulatory deferral account balances.

These financial statements have been prepared on a historical cost basis. These financial statements are presented in Canadian dollars and were approved by the Corporation's Board of Directors on April 16, 2020.

(b) **Effects of rate regulation**

The Ontario Energy Board (OEB) is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate regulated corporation. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers in future periods through the rate-setting and approval process.

(c) **Cash and cash equivalents**

Cash and cash equivalents are defined as cash and highly liquid investments, consisting primarily of term deposits, with terms to maturity of three months or less at the date of purchase.

(d) **Inventory**

Inventory is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

2. Significant accounting policies, continued

(e) Property, plant and equipment

Property, plant and equipment are measured at historical cost less accumulated depreciation and impairment losses, if any. In circumstances where parts of an item of property, plant and equipment have different useful lives they are accounted for as separate components of property, plant and equipment. The Corporation provides for depreciation using the straight-line method at rates designed to depreciate the cost of the property, plant and equipment over their estimated useful lives. A full year's depreciation is recorded in the year of acquisition. No depreciation is recorded in the year of disposal. The carrying amount of an item of property, plant and equipment is derecognized on disposal. The annual depreciation rates and useful lives are reviewed annually and are as follows:

Buildings	50 years
Furniture and equipment	5-10 years
Vehicles	15 years
Transmission and distribution equipment	40-60 years

Construction in progress includes assets not currently in use and therefore not yet subject to depreciation.

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are classified as liabilities and are amortized at the same rate as the assets to which they relate.

2. **Significant accounting policies, continued**

(f) **Impairment of non-financial assets**

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit ("CGU") to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual CGUs, or otherwise they are allocated to the smallest group of CGUs for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs to sell and value in use. 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 for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount. An impairment loss is recognized immediately in operations.

Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in operations.

(g) **Goodwill**

Goodwill represents the difference between the acquisition cost of the Corporation and the fair value of the net assets acquired. Goodwill is not amortized, but is subject to fair value impairment tests annually. Goodwill is allocated to reporting units and any potential goodwill impairment is identified by comparing the carrying value of the reporting unit with its fair value. If any potential impairment is identified, then the amount of the impairment is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Any impairment of goodwill is charged to operations in the period in which the impairment is determined

(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 rate, net of tax, that reflects current market assessments of the time value of money and the risks specific to the liability.

2. **Significant accounting policies, continued**

(i) **Borrowing costs**

Borrowing costs directly attributable to the acquisition or construction of property, plant and equipment, which take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other borrowing costs are recognized in operations in the period in which they are incurred.

(j) **Asset retirement obligations**

Accounting standards require the Corporation to determine the fair value of future expenditures required to settle legal obligations to remove property, plant and equipment. If reasonably estimable, the Corporation recognizes a liability for the estimated current value of future expenditures required to settle obligations for the retirement of property, plant and equipment. Decommissioning liabilities are recorded at fair value, with a corresponding increase to the recorded amount of property, plant and equipment. Accretion of decommissioning liabilities are included in operations. Differences between the recorded amount of decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the period of settlement.

Some of the Corporation's distribution system assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of the related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

(k) **Pension plan**

The Corporation provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan that 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.

OMERS is a defined benefit plan, however it 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. Obligations for contributions to defined contribution pension plans are recognized as an expense in operations when they are due.

2. **Significant accounting policies, continued**

(l) **Revenue recognition**

Distribution and energy related revenues attributable to the supply and distribution of electricity are based on OEB approved rates and revenue is recognized as electricity is delivered to customers based on periodic meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available and no bills have been issued. This unbilled revenue is estimated and recorded in current assets on the statement of financial position at the end of each fiscal period. The related cost of energy is recorded on the basis of energy used.

The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers for energy sales based on regulated rates are recorded on the statement of financial position as regulatory assets and liabilities until their final disposition is decided by the OEB. In accordance with IFRS 14, the change in these regulatory assets and liabilities are reported, net of tax, with regulatory balances in the statement of comprehensive earnings.

Labour, rental and other charges revenue are recognized in the period in which these services are provided.

(m) **Payment in lieu of taxes**

Pursuant to the EA, the Corporation is required to compute taxes under the Income Tax Act (Canada) (ITA) and remit such amounts computed there under to the Ontario Electricity Financial Corporation (OEFC). These amounts, referred to as payments in lieu of taxes (PILs) under the EA, are applied to reduce certain debt obligations of the former Ontario Hydro now owing by the OEFC.

Payment in lieu of deferred income tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amount of assets and liabilities and their tax bases. Payment in lieu of deferred tax assets are also recognized for the benefit of any deductions or losses available to be carried forward to future periods for tax purposes that are likely to be realized. These amounts are measured using enacted or substantively enacted tax rates and are re-measured annually for changes in these rates. Any payment in lieu of deferred income tax assets are reassessed each fiscal period to determine if a valuation allowance is required. Any effect of the re-measurement or reassessment is recognized in operations in the period of the change.

As prescribed by regulatory rate order, payment in lieu of taxes are recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of payment in lieu of deferred taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, payment in lieu of deferred tax regulatory assets or liabilities are recognized for the amount of payment in lieu of deferred taxes which are expected to be included in future rates and recovered from or refunded to customers in future periods through the rate setting and approval process.

2. **Significant accounting policies, continued**

(n) **Employee future benefits**

The Corporation’s net obligation in respect of its employee future benefit plan is calculated by estimating the amount of future benefits that employees have earned in return for their service in the current and prior periods, that benefit is discounted to determine its present value. Any unrecognised past service costs are deducted. The discount rate is the interest rate at the reporting date on high quality debt instruments with duration similar to the duration of the plan.

The cost of these employee future benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management’s best estimate of certain underlying assumptions. Re-measurements arising from employee benefit plans are recognized immediately in operations. When the benefits of a plan are improved, these increases are recognized immediately in operations.

(o) **Financial instruments**

(i) **Measurement of financial instruments**

All of the Corporation's financial assets and financial liabilities are initially measured at fair value. Fair value is the amount for which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Transaction costs, that are directly attributable to the acquisition or issue of financial assets and financial liabilities, are added to the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition.

Subsequent to initial recognition these financial assets and financial liabilities are measured at their amortized cost. Amortized cost is the amount at which the financial instrument is measured at initial recognition less principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount. Interest rate swaps that are not hedging items are measured at fair value and changes in fair value are recognized in operations in the period they occur.

2. **Significant accounting policies, continued**

(o) **Financial instruments, continued**

(ii) **Impairment**

A financial asset measured at amortized cost is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in operations. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in operations.

(p) **Measurement uncertainty**

The preparation of financial statements in conformity with International Financial Reporting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. By their nature, these estimates are subject to measurement uncertainty. The effect of changes in such estimates on the financial statements in future periods could be significant, including changes as a result of future decisions made by the Ontario Energy Board (OEB). All estimates are reviewed periodically and adjustments are made and recognized in operations, as appropriate, in the period they become known. Accounts specifically affected by estimates and assumptions in these financial statements are as follows:

(i) **Property, plant and equipment**

Amounts recorded in the financial statements for depreciation are based on the estimated useful lives of the Corporation's property, plant and equipment. These useful lives are management's best estimate of the service lives of these assets and are reviewed annually. Changes to these estimated useful lives could materially affect the amount of depreciation recorded in the financial statements.

The Corporation's policy relating to property, plant and equipment is described in note 2(e). In applying this policy, management uses judgment in determining whether certain costs are additions to the carrying amount of property, plant and equipment or expensed in operations as repairs and maintenance. Judgment is also necessary in determining the appropriate componentization structure of the Corporation's property, plant and equipment.

2. **Significant accounting policies, continued**

(p) **Measurement uncertainty, continued**

(ii) **Payment in lieu of taxes**

Significant judgment is required in determining the provision for payment in lieu of taxes. There are many judgments and calculations made for which the ultimate tax determination is uncertain. The Corporation recognizes tax assets and liabilities based on the Corporation's interpretation of current tax law. Where the final outcome of these interpretations is different from the amounts that were originally recorded, these differences are recognized in the current and deferred income tax provisions in the period in which the determination is made.

(iii) **Employee future benefits**

The Corporation provides certain health and dental benefits to retired employees. The estimated cost of providing these benefits is accounted for on an accrual basis in the period in which employees render their services and are actuarially determined using the projected benefit method pro-rated on service and include management's best estimate of salary escalations, retirement ages and expected health care cost escalations.

(iv) **Regulatory assets and liabilities**

When recognizing regulatory assets and liabilities management assumes that such credits or costs will be recovered from customers or refunded to customers in future years through the rate setting and approval process. Refund or recovery of these regulatory assets and liabilities are subject to the review and approval of the OEB. Consequently, there is risk that some or all of the regulatory assets and liabilities will not be approved by the OEB which could have a material affect on the Corporation's comprehensive income in the year of the OEB decision.

3. **Future changes to significant accounting policies**

The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2019. There are currently no IFRS standards that have been issued, but that are not yet effective, that would have a material affect on the Corporation's financial statements beginning on or after January 1, 2020.

4. Accounts receivable

	December 31, 2019	September 30, 2019
Electrical energy receivables	$ 803,305	$ 615,877
Water and sewer receivables	-	431,174
Other receivables	422,899	203,204
	$ 1,226,204	$ 1,250,255

	December 31, 2019	September 30, 2019
Aging of accounts receivable:		
Current	$ 1,210,533	$ 995,349
30 days	13,925	242,186
60 days	1,746	8,927
Over 90 days	-	3,793
	$ 1,226,204	$ 1,250,255

5. Property, plant and equipment

December 31, 2019

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of	$ 88,880	183,831	5,276,320	385,981	41,654	56,105	$ 6,032,771
Additions	-	-	77,863	-	6,341	3,526	87,730
Transfers	-	-	-	-	-	-	-
Disposals	-	-	-	-	-	-	-
Balance, end of period	88,880	183,831	5,354,183	385,981	47,995	59,631	6,120,501
Accumulated Amortization							
Balance, beginning of	-	26,088	747,301	126,649	26,727	-	926,765
Depreciation	-	1,143	40,415	6,819	244	-	48,621
Disposals	-	-	-	-	-	-	-
Balance, end of period	-	27,231	787,716	133,468	26,971	-	975,386
Net book value	$ 88,880	156,600	4,566,467	252,513	21,024	59,631	$ 5,145,115

September 30, 2019

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of year	$ 88,880	183,831	4,986,951	315,642	33,070	51,184	$ 5,659,558
Additions	-	-	289,369	70,339	8,584	4,921	373,213
Transfers	-	-	-	-	-	-	-
Disposals	-	-	-	-	-	-	-
Balance, end of year	88,880	183,831	5,276,320	385,981	41,654	56,105	6,032,771
Accumulated Amortization							
Balance, beginning of year	-	22,659	627,438	106,188	23,058	-	779,343
Depreciation	-	3,429	119,863	20,461	3,669	-	147,422
Disposals	-	-	-	-	-	-	-
Balance, end of year	-	26,088	747,301	126,649	26,727	-	926,765
Net book value	$ 88,880	157,743	4,529,019	259,332	14,927	56,105	$ 5,106,006

6. **Regulatory assets and liabilities**

	September 30, 2019	Regulatory activity	December 31, 2019
Settlement variances (a)	$ 1,492,061	$ (164,151)	$ 1,327,910
Stranded meters (b)	9,040	12	9,052
Substation (c)	1,223,160	(31,074)	1,192,086
Payment in lieu of deferred tax regulatory assets (d)	50,998	116,982	167,980
Total regulatory assets	2,775,259	(78,231)	2,697,028
Settlement variances (a) - liability	442,463	124,895	567,358
Total regulatory liabilities	442,463	124,895	567,358
Net regulatory assets	$ 2,332,796	$ (203,126)	$ 2,129,670

	January 1, 2019	Regulatory activity	September 30, 2019
Settlement variances (a)	$ 1,210,588	$ 281,473	$ 1,492,061
Stranded meters (b)	9,304	(264)	9,040
Substation (c)	1,323,620	(100,460)	1,223,160
Payment in lieu of deferred tax regulatory assets (d)	102,932	(51,934)	50,998
Total regulatory assets	2,646,444	128,815	2,775,259
Settlement variances (a) - liability (reduction)	489,389	(46,926)	442,463
Total regulatory liabilities	489,389	(46,926)	442,463
Net regulatory assets	$ 2,157,055	$ 175,741	$ 2,332,796

6. **Regulatory assets and liabilities, continued**

In accordance with IFRS 14 - Regulatory deferral accounts, the Corporation has continued to apply the accounting policies that it applied, in accordance with CPA Canada Handbook Part V - pre-changeover accounting standards, prior to its adoption of International Financial Reporting Standards. Regulatory assets and liabilities arise as a result of the rate setting and approval process through the OEB.

(a) The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers as energy sales, based on regulated rates, are recorded on the statement of financial position as settlement variances until their final disposition is decided by the OEB. The Corporation recognizes settlement variances as an asset or liability based on the expectation that these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The settlement variance asset (liability) represents the excess (deficiency) of amounts billed to the Corporation by Hydro One for the purchase of energy over the amounts charged by the Corporation to its customers as energy sales. Currently, no amounts for settlement variances have been approved by the OEB for recovery or refund. Accordingly, the timing of the recovery or refund is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have decreased by $289,046 in the three month period ended December 31, 2019 ($328,399 increase for the nine month period ended September 30, 2019) related to amounts recognized for settlement variances.

(b) The stranded meter regulatory asset represents the unrecovered net book value of decommissioned analogue meters. At the direction of the OEB, the net book value of the stranded meters were reclassified to the regulatory asset account for recovery in rates to the end of March 2017. Currently, no amounts for stranded meters have been approved by the OEB for recovery. Accordingly, the timing of the recovery is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have increased by $NIL in the three month period ended December 31, 2019 ($NIL for the nine month period ended September 30, 2019) related to amounts recognized for the substation.

(c) The substation asset represents the cost of construction of a new substation in the Town of Espanola. The OEB approved the recovery for substation costs of $168,193 per year in the Corporation's rates until their next cost of service rate order.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have increased by $37,055 in the three month period ended December 31, 2019 ($120,341 increase for the nine month period ended September 30, 2019) related to amounts recognized for the substation.

6. **Regulatory assets and liabilities, continued**

(d) The payment in lieu of deferred tax regulatory asset represents the expected increase in distribution rates for customers arising from temporary differences which give rise to payment in lieu of deferred tax liabilities. Currently, no amounts for payment in lieu of deferred taxes have been approved by the OEB for recovery. Accordingly, the timing of the recovery is unknown.

For certain of the regulatory assets and liabilities, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund of each of its regulatory liabilities and continues to believe that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. **Operating loan**

A revolving operating loan credit facility has been granted by The Toronto Dominion Bank to a maximum of $500,000 bearing interest at the bank's prime rate of interest per annum.

This credit facility is secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited, a related company.

8. **Advances from related company**

The corporation is related to North Bay Hydro Distribution Limited by virtue of common controlling shareholders. The corporation is a wholly owned subsidiary of North Bay Hydro Holdings Limited.

	December 31, 2019	September 30, 2019
North Bay Hydro Distribution Limited	$ 551,351	$ -

The advances from North Bay Hydro Distribution Limited are unsecured, bear interest at the prime rate of interest on the first $200,000 of advances only, and have no specific terms of repayment.

9. **Payment in lieu of taxes**

(a) The components of payment in lieu of deferred tax balances are as follows:

	December 31, 2019	September 30, 2019
Payment in lieu of deferred tax assets:		
Difference between tax basis of long-term obligations and carrying amount	$ 12,365	$ -
Difference between tax basis of employee future benefits obligation and carrying amount	26,114	12,274
Carrying value of loss carryforward deferred tax asset	93,049	70,185
Payment in lieu of deferred tax liabilities:		
Difference between tax basis of property, plant and equipment and carrying amount	(299,508)	(133,457)
	$ (167,980)	$ (50,998)

(b) The provision for payment in lieu of taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 26.5% (September 2019 - 12.5%) to the earnings (loss) for the periods as follows:

	December 31, 2019	September 30, 2019
Earnings (loss) for the period before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	$ 225,911	$ (357,003)
Change in regulatory asset and liability account balances related to profit and loss	(320,108)	227,675
Remeasurement of employee future benefits liability included in other comprehensive income	-	(12,469)
	$ (94,197)	$ (141,797)
Anticipated income tax recovery	$ (24,962)	$ (17,725)
Tax effect of the following:		
Tax effect of change in regulatory assets	62,258	(26,493)
Tax effect of change in payment in lieu of deferred tax regulatory asset	11,252	(3,180)
Adjustment due to change in tax rate	68,434	(6,561)
Provision for (recovery of) payment in lieu of taxes	$ 116,982	$ (53,959)

(c) For income tax purposes, the Corporation has a loss of $351,128 which can be applied to reduce future years' taxable income. This loss expires in 2038.

10. Contributions in aid of construction

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are deferred and amortized to other revenue at the same rate as the assets to which they relate.

	December 31, 2019	September 30, 2019
Balance, beginning of period	$ 348,367	$ 316,758
Contributions received in the period	100	39,190
Amortization of contributions in aid of construction	(2,527)	(7,581)
Balance, end of period	$ 345,940	$ 348,367

11. Employee future benefits

The Corporation pays certain post-employment health and dental benefits on behalf of its retired employees. Accounting standards for employee future benefits require that these post-retirement costs be recognized in the period in which the employees rendered their services. Information about the Corporation's accrued benefit obligation and the related expense are based on results and assumptions by actuarial valuation at September 30, 2019 and are as follows:

	December 31, 2019	September 30, 2019
Accrued benefit obligation, beginning of period	$ 98,197	$ 84,387
Current service cost recognized in operations	242	725
Interest cost recognized in operations	734	2,504
Benefits paid by employer	(630)	(1,888)
Net actuarial loss recognized in other comprehensive income	-	12,469
Accrued benefit obligation, end of period	$ 98,543	$ 98,197

11. **Employee future benefits, continued**

The main assumptions employed for the valuation of the employee future benefit obligation are as follows:

The health benefit cost is estimated to increase at a rate of 4.0% (September 2019 - 4.0%) per annum. The dental benefit cost is estimated to increase at a rate of 4.3% (September 2019 - 4.3%) per annum.

The obligation at period-end and the present value of future obligations and the related expense, were determined using an annual discount rate of 3.0% per annum (September 2019 - 3.0%) representing an estimate of the yield on high quality corporate bonds with a duration similar to the duration of the plan.

Future general salary and wage levels were assumed to increase at 2.5% (September 2019 - 2.5%) per annum.

12. **Long-term obligations**

	December 31, 2019	September 30, 2019
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $2,860 including interest at 2.73% per annum, maturing December 2025	$ 189,713	$ 196,964
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $10,831 including interest at 3.78% per annum, maturing December 2040	1,881,898	1,896,515
Toronto Dominion Bank committed reducing term facility by way of a floating rate term loan available by way of bankers acceptances, maturing October 2044 (see below for terms)	7,789,530	-
Interest rate swap mark-to-market adjustment	46,660	-
	9,907,801	2,093,479
Less current portion	89,370	88,608
	$ 9,818,431	$ 2,004,871

12. **Long-term obligations , continued**

The Ontario Infrastructure and Lands Corporation loans are secured by a general security agreement ranking behind the first ranking general security agreement registered by The Toronto Dominion Bank (note 7), an inter-creditor agreement between Ontario Infrastructure and Lands Corporation and The Toronto Dominion Bank and a guarantee provided by North Bay Hydro Distribution Limited.

The Corporation has entered into an interest rate swap derivative agreement with the Toronto Dominion Bank to manage the volatility of the interest rate on the committed reducing term facility. The loan is being repaid over 300 months with interest only repayments of $19,006 for 36 months until October 2022 then principal and interest repayments of $40,057 for 264 months until October 2044, with interest at a fixed rate of 2.928% per annum. The fair value of this loan is $7,836,190 which is estimated by obtaining mark-to-market quotes from the Toronto Dominion Bank resulting in an interest rate swap mark-to-market adjustment of $46,660. The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

The Toronto Dominion Bank committed reducing term facility is secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited.

The Ontario Infrastructure and Lands Corporation loans require the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:30 to 1 and a debt to total assets ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2023 fiscal period.

The Toronto Dominion Bank loan requires the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:20 to 1 and a debt to capitalization ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2022 fiscal period.

Estimated principal repayments required to settle long-term obligations are as follows, (excludes interest rate swap mark-to-market adjustment):

2020	$ 89,370
2021	92,489
2022	137,871
2023	356,338
2024	367,437
Subsequent years	8,817,636
	$ 9,861,141

13. Notes payable

	December 31, 2019	September 30, 2019
Note payable to the Town of Espanola	$ -	$ 1,185,416
Note payable to the Township of Sables-Spanish Rivers	-	339,095
	$ -	$ 1,524,511

Notes payable to the Town of Espanola and Township of Sables-Spanish Rivers were without security, due on demand with one year's written notice, included interest at 4.41% per annum ,and convertible into special shares of the Corporation at a rate of $10,000 per share. During the period, the Corporation paid interest in the amount of $Nil (September 2019 - $39,208) to the Town of Espanola and $Nil (September 2019 - $11,216) to the Township of Sables-Spanish Rivers.

Upon closing of the acquisition on October 1, 2019 the promissory notes payable were cancelled (note 21).

14. Share capital

	December 31, 2019	September 30, 2019
Authorized		
Unlimited number of common shares		
Issued		
100 common shares (September 2019 - 1,000 common shares (note 21))	$ 100	$ 1,000
228 discretionary non-cumulative dividend paying, redeemable at $10,000 per share, non-voting special shares (note 21)	-	2,280,000
	$ 100	$ 2,281,000

15. **Operating expenses**

For internal management reporting purposes the Corporation's operating expenses are reported by function. Operating expenses reported by object are as follows:

	December 31, 2019	September 30, 2019
Salaries, wages and benefits	$ 150,617	$ 391,512
Contracted services	107,785	347,508
Office and administration	108,270	241,583
Operations and maintenance	43,108	187,408
Depreciation	48,621	147,422
Bad debts (recovery)	(4,911)	63,098
	$ 453,490	$ 1,378,531

16. **Change in non-cash working capital items**

	December 31, 2019	September 30, 2019
Accounts receivable	$ 24,051	$ 122,612
Unbilled revenue - energy sales	(509,697)	249,995
Unbilled revenue - distribution	(42,362)	37,795
Inventory	(3,844)	6,178
Prepaid expenses	23,678	17,952
Payment in lieu of taxes paid	(2)	79,413
Accounts payable and accrued liabilities	(1,008,292)	(6,106)
Payable for energy purchases	675,874	(275,862)
	$ (840,594)	$ 231,977

17. Pension plan

The Corporation provides pension benefits to its employees through the Ontario Municipal Employees Retirement System (OMERS) pension plan. The plan is a multi-employer, contributory, defined benefit pension plan funded by equal contributions by both employer and employees. During the period the Corporation made employer contributions of $14,908 (September 2019 - $47,047) to OMERS.

At December 31, 2019 the OMERS pension plan had total assets of $122.5 billion (2018 - $111.8 billion) and an accumulated deficit of $3.397 billion (2018 - $4.191 billion deficit).

18. Commitments

The corporation has entered into a contract for management, billing, collecting, customer service, software and data hosting services and support with PUC Services Inc. expiring February 28, 2022 at a base cost as follows:

2020	$ 177,423
2021	180,958
2022	30,408

In addition to the above charges, a monthly charge of $5.53 to $5.75 per meter, for up to 3,700 meters for residential and general service customers, will also apply.

19. Capital disclosure

The Corporation's objectives when managing capital are:

(a) Ensure ongoing access to capital at a reasonable cost in order to maintain and improve the electricity distribution system of the Corporation to ensure the continued delivery of safe, reliable electricity services to customers, and to safeguard the Corporation's ability to continue as a going concern and provide a reasonable rate of return to its shareholders;

(b) Maintain the Corporation’s capital structure with the financial ratios and recommended guidelines prescribed by the OEB.

The Corporation’s capital consists of its common share capital, retained earnings (deficit) operating loans and long-term obligations. In order to achieve the above noted objectives the Corporation develops detailed annual operating and capital budgets and seeks to control costs to meet its working capital and capital investment requirements on both a short-term and long-term basis. There have been no changes in the Corporation’s approach to managing capital during the period.

At December 31, 2019 the Corporation is party to debt agreements with Ontario Infrastructure and Lands Corporation (note 12) and The Toronto Dominion Bank (notes 7 and 12) that contain certain covenants that restrict the Corporation from incurring additional debt or making distributions to shareholders in excess of certain limits, that would cause a violation of those covenants.

20. Financial instruments

Transactions in financial instruments may result in an entity assuming or transferring financial risks to or from another party. The Corporation is exposed to the following risks associated with financial instruments and transactions it is a party to:

(a) Fair value

The fair value of current financial assets and current financial liabilities approximates their carrying value due to their short-term maturity dates. The fair value of long-term financial liabilities approximates their carrying value based on the presumption that the Corporation is a going concern and thus expects to fully repay the outstanding amounts. Fair value of derivative financial instruments is estimated by obtaining mark-to-market quotes from The Toronto Dominion Bank. The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

20. **Financial instruments, continued**

(b) Credit risk

Credit risk is the risk that one party to a financial transaction will fail to discharge a financial obligation and cause the other party to incur a financial loss. The Corporation's main credit risks are associated with its cash and accounts receivable.

The Corporation minimizes credit risk associated with its cash balances by ensuring that these financial assets are held with large reputable financial institutions with high credit ratings.

The Corporation incurs amounts due from its customers in the regular course of business and has credit risk associated with its accounts receivable balances of $1,226,204 (September 30, 2019 - $1,250,255). The Corporation reduces its exposure to credit risk through management's on-going monitoring of its accounts receivable balances and collections. Credit valuations are performed on a regular basis and credit is granted upon a review of the credit history of the applicant. An allowance for bad debts is recorded when applicable.

(c) Liquidity risk

Liquidity risk is the risk that the Corporation cannot repay its obligations when they become due to its creditors. The Corporation has liquidity risk associated with its operating loan, accounts payable and accrued liabilities, payable for energy purchases and long-term obligations. The Corporation reduces its exposure to liquidity risk by ensuring that it documents when authorized payments become due, and budgets to maintain adequate cash resources including an operating line of credit, to repay creditors including long-term obligations interest and principal as those liabilities become due.

The majority of the Corporation's accounts payable and payable for energy purchases, as reported in the statement of financial position, are due within 30 days.

21. **Business combination**

On October 1, 2019, North Bay (Espanola) Acquisition Inc., a wholly owned subsidiary of North Bay Hydro Holdings Ltd. acquired, for $7,992,237 of cash consideration, all of the outstanding shares of all classes of Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation (the "purchased securities").

This acquisition was accounted for as a business combination using the acquisition method of accounting whereby the acquired tangible and intangible assets and assumed liabilities are recorded in these financial statements at their estimated fair values at the date of acquisition.

Immediately after the acquisition North Bay (Espanola) Acquisition Inc., Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation amalgamated to form this corporation, which has continued operations under the name Espanola Regional Hydro Distribution Corporation. The results of operations are included in the accounts from the effective date of acquisition of October 1, 2019.

Details of the acquisition of the purchased securities are as follows:

		October 1, 2019
Purchased securities:		
1,000 common shares issued by Espanola Regional Hydro Holdings Corporation	$	4,187,726
228 special shares issued by Espanola Regional Hydro Distribution Corporation		2,280,000
Promissory notes payable issued by Espanola Regional Hydro Distribution Corporation		1,524,511
Total purchase price	$	7,992,237

21. **Business combination, continued**

Fair value of assets acquired:		
Current assets	$	2,209,844
Property, plant and equipment		5,106,006
Regulatory assets		2,775,259
		10,091,109
Liabilities assumed:		
Current liabilities		2,138,205
Customer deposits		223,680
Deferred revenue		114,098
Payment in lieu of deferred taxes		50,998
Contributions in aid of construction		348,367
Employee future benefits		98,197
Long-term obligations		2,004,871
Promissory notes payable		1,524,511
Regulatory liabilities		442,463
Fair value of net assets acquired	$	3,145,719

Upon closing of the acquisition the promissory notes payable were cancelled.

The total purchase price has been allocated as follows:

Fair value of net assets acquired	$	3,145,719
Goodwill recognized		3,322,007
Cancellation of promissory notes payable		1,524,511
Fair value of net assets recognized	$	7,992,237

The determination of fair values and the purchase price equation are based upon an independent valuation. The primary drivers to generate goodwill are business synergies and opportunities in another region. The goodwill is not deductible for income tax purposes. The Corporation has recognized $368,523 in acquisition related expenses. All acquisition related expenses have been expensed in the accounts of the Corporation.

See note 22 regarding the presentation of comparative figures in these financial statements.

22. Comparative figures

The objective of financial statements are to communicate information that is useful to investors, creditors and other users in making resource-allocation decisions and assessing management's stewardship. Comparative figures are required to be meaningful to the users of these financial statements.

In a vertical amalgamation the amalgamated enterprise is legally a continuation of the predecessor enterprises. However, since control changed immediately prior to the amalgamation the comparative figures cannot consist of the consolidated financial information of all of the predecessor enterprises. Accordingly, these comparative figures represent only the assets, liabilities, shareholders' equity, revenues and expenses of the former Espanola Regional Hydro Distribution Corporation because these figures represent the most meaningful and useful comparators.

The adjustment to retained earnings for pushdown accounting on amalgamation reflected in the statement of retained earnings and other comprehensive earnings (loss) consists of the following:

	October 1, 2019
Reduction for total shareholders' equity of predecessor entities (note 21)	$ 3,145,719
Adjustment for accumulated deficit of North Bay (Espanola) Acquisition Inc. at the date of acquisition	368,523
Amalgamation adjustment at October 1, 2019	$ 3,514,242

23. Subsequent events

Subsequent to year end, the impact of COVID-19 in Canada and on the global economy increased significantly. The global pandemic has disrupted economic activities and supply chains. Although the disruption from the virus is expected to be temporary, given the dynamic nature of these circumstances, the duration of the business disruption and related financial impact cannot be reasonably estimated at this time. The entity's ability to continue to service debt and meet obligations as they come due is dependent on the continued ability to generate earnings and cash flows. At this time, the full potential impact of COVID-19 on the entity is not known.

Espanola Regional Hydro Distribution Corporation

Financial Statements

Year ended December 31, 2020

INDEPENDENT AUDITOR'S REPORT

To: The Shareholder of
Espanola Regional Hydro Distribution Corporation

Opinion
We have audited the financial statements of **Espanola Regional Hydro Distribution Corporation**, which comprise the statement of financial position as at **December 31, 2020**, and the statements of comprehensive loss, retained earnings (deficit) and accumulated other comprehensive earnings (loss), and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at **December 31, 2020**, 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 Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical 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 Corporation'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 Corporation or to cease operations, or has no realistic alternative but to do so.

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

INDEPENDENT AUDITOR'S REPORT, continued

Auditor's 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 auditor's 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 these 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 Corporation'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 Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's 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 auditor's report. However, future events or conditions may cause the Corporation 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.

INDEPENDENT AUDITOR'S REPORT, continued

We 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.

Freelandt Caldwell Reilly LLP

FREELANDT CALDWELL REILLY LLP

Chartered Professional Accountants
Licensed Public Accountants

Sudbury, Ontario
March 26, 2021

Espanola Regional Hydro Distribution Corporation
Statement of Financial Position
December 31, 2020 with comparative figures for 2019

		2020		2019
Assets				
Current				
Cash	$	226,305	$	317,887
Accounts receivable (note 4)		1,345,628		1,226,204
Unbilled revenue - energy sales		769,490		791,739
Unbilled revenue - distribution		153,415		156,681
Inventory		58,247		48,049
Prepaid expenses - current		146,145		118,235
Payment in lieu of taxes		-		1,816
		2,699,230		2,660,611
Advances to corporate shareholder		100		100
Prepaid expenses - non-current		398,041		-
Payment in lieu of deferred taxes (note 9)		151,790		-
Property, plant and equipment (note 5)		5,502,180		5,145,115
Goodwill		3,322,007		3,322,007
Total assets		12,073,348		11,127,833
Regulatory assets (note 6)		2,402,613		2,697,028
Total assets and regulatory assets	$	14,475,961	$	13,824,861

Approved on behalf of the Board of Directors:

Director ____________

Director ____________

Espanola Regional Hydro Distribution Corporation

Statement of Financial Position

December 31, 2020 with comparative figures for 2019

		2020		2019
Liabilities and shareholders' equity (deficiency)				
Current				
Operating loan (note 7)	$	105,000	$	235,000
Accounts payable and accrued liabilities		1,089,136		585,203
Payable for energy purchases		1,784,492		1,854,606
Advances from related company (note 8)		704,198		200,000
Current portion of long-term obligations		108,952		89,370
		3,791,778		2,964,179
Customer deposits		198,754		220,351
Deferred revenue		-		104,799
Payment in lieu of deferred taxes (note 9)		-		167,980
Contributions in aid of construction (note 10)		343,376		345,940
Employee future benefits (note 11)		103,867		98,543
Long-term obligations (note 12)		10,308,742		9,771,771
Interest rate swap mark to market adjustment (note 12)		806,133		46,660
		15,552,650		13,720,223
Shareholders' equity (deficiency)				
Share capital (note 13)		100		100
Retained earnings (deficit)		(1,499,990)		(462,820)
Accumulated other comprehensive earnings (loss)		(6,060)		-
		(1,505,950)		(462,720)
Total liabilities and shareholders' equity (deficiency)		14,046,700		13,257,503
Regulatory liabilities (note 6)		429,261		567,358
Total liabilities, shareholder's equity (deficiency) and regulatory liabilities	$	14,475,961	$	13,824,861

Commitments (note 17)
Uncertainty due to COVID-19 (note 20)

Espanola Regional Hydro Distribution Corporation

Statement of Comprehensive Loss

Year ended December 31, 2020 with comparative figures for the three month period from October 1, 2019 to December 31, 2019

	2020	2019 (3 months)
Revenue		
Energy sales	$ 8,463,669	$ 2,363,438
Distribution	1,628,387	429,486
	10,092,056	2,792,924
Cost of Energy	8,627,121	2,043,330
Gross Profit	1,464,935	749,594
Operating expenses (note 14)		
General and administration	427,262	159,978
Billing and collecting	417,997	87,360
Distribution - operations	399,646	95,436
Distribution - maintenance	315,903	68,915
Depreciation	184,159	41,801
	1,744,967	453,490
Earnings (loss) before other income (expense) and payment in lieu of taxes	(280,032)	296,104
Other income (expense)		
Interest	33,570	26,048
Labour, rental and other charges	103,572	21,702
Amortization of contributions in aid of construction	7,711	2,527
Interest on long-term obligations	(305,970)	(73,810)
Interest rate swap mark-to-market adjustment (note 12)	(759,473)	(46,660)
	(920,590)	(70,193)
Earnings (loss) before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	(1,200,622)	225,911
Payments in lieu of taxes (recovery) (note 9)		
Current	-	-
Deferred	(319,770)	116,982
Net earnings (loss) before change in regulatory asset and liability balances and other comprehensive earnings (loss)	(880,852)	108,929
Change in regulatory assets and liabilities (note 6)		
Change in regulatory asset and liability account balances related to profit and loss	163,452	(320,108)
Change in regulatory asset account balance related to payment in lieu of deferred taxes	(319,770)	116,982
	(156,318)	(203,126)
Net loss before other comprehensive loss	(1,037,170)	(94,197)
Other comprehensive loss		
Remeasurement of employee future benefits liability, net of tax	(6,060)	-
Net comprehensive loss	$ (1,043,230)	$ (94,197)

See accompanying notes to financial statements

Espanola Regional Hydro Distribution Corporation

Statement of Retained Earnings (deficit) and Accumulated Other Comprehensive Earnings (Loss)

Year ended December 31, 2020 with comparative figures for the three month period from October 1, 2019 to December 31, 2019

	Share capital	Retained earnings (deficit)	Accumulated other comprehensive earnings (loss)	Total
Balance at January 1, 2020	100	(462,820)	-	(462,720)
Net earnings (loss) before other comprehensive loss	-	(1,037,170)	-	(1,037,170)
Other comprehensive earnings (loss)	-	-	(6,060)	(6,060)
Balance at December 31, 2020	100	(1,499,990)	(6,060)	(1,505,950)
Balance at October 1, 2019	100	(368,623)	-	(368,523)
Net earnings (loss) before other comprehensive loss (3 months)	-	(94,197)	-	(94,197)
Other comprehensive earnings (loss)	-	-	-	-
Balance at December 31, 2019	100	(462,820)	-	(462,720)

See accompanying notes to financial statements

Espanola Regional Hydro Distribution Corporation

Cash Flows Statement
Year ended December 31, 2020
with comparative figures for the three month period from October 1, 2019 to 2019

	2020	2019 (3 months)
Cash flows from operating activities		
Net loss	$ (1,043,230)	$ (94,197)
Adjustments to reconcile earnings to cash provided by (used in) operations:		
Depreciation	210,282	48,621
Amortization of contributions in aid of construction	(7,711)	(2,527)
Provision for payment in lieu of deferred taxes	(319,770)	116,982
Interest rate swap mark-to-market adjustment	759,473	46,660
	(400,956)	115,539
Change in non-cash working capital items (note 15)	(94,423)	(840,594)
	(495,379)	(725,055)
Cash flows from investing activities		
Purchase of property, plant and equipment	(567,347)	(87,730)
Regulatory assets	294,415	78,231
	(272,932)	(9,499)
Cash flows from financing activities		
Operating loan	(130,000)	235,000
Advances from related company	504,198	351,351
Customer deposits	(21,597)	(3,329)
Deferred revenue	(104,799)	(9,299)
Regulatory liabilities	(138,097)	124,895
Contributions in aid of construction	5,147	100
Employee future benefits	5,324	346
Proceeds on long-term debt	650,000	-
Repayment of long-term obligations	(93,447)	(26,317)
	676,729	672,747
Decrease in cash	(91,582)	(61,807)
Cash, beginning of year	317,887	379,694
Cash, end of year	$ 226,305	$ 317,887

1. Nature of operations

Espanola Regional Hydro Distribution Corporation was created on October 1, 2019 by the amalgamation of North Bay (Espanola) Acquisition Inc., Espanola Regional Hydro Holdings Corporation and Espanola Regional Hydro Distribution Corporation. The corporation is required in accordance with the Electricity Act, 1998, Ontario (the EA), is a wholly owned subsidiary of North Bay Hydro Holdings Limited, and was created for the purpose of providing regulated electricity distribution services to customers in the Town of Espanola and the Township of Sables-Spanish Rivers from its head office located at 598 Second Street, Espanola Ontario, Canada.

The Corporation and other electricity distributors purchase their electricity from the wholesale market administered by the Independent Electricity System Operator (IESO) and recover the costs of electricity and certain other costs from customers under the authority of the Ontario Energy Board (the OEB) Act, 1998.

The OEB has regulatory oversight of electricity matters in the Province of Ontario. The Ontario Energy Board Act, 1998 sets out the OEB's authority to issue a distribution licence which must be obtained by owners or operators of a distribution system in Ontario. The OEB prescribes licence requirements and conditions including, among other things, specified accounting records, regulatory accounting principles and the filing process requirements for rate-setting purposes.

The OEB's authority and responsibilities include the power to approve and fix rates for the transmission and distribution of electricity and the responsibility for ensuring that electricity distribution companies fulfil their obligations to connect and service customers.

Regulatory developments in Ontario's electricity industry may affect distribution rates and the permitted recovery or settlement or the timing of recovery or settlement of certain regulatory assets and liabilities.

2. **Significant accounting policies**

These financial statements are prepared using International Financial Reporting Standards applying the accounting policies set out below on a consistent basis in all periods presented in these financial statement. The significant policies are detailed as follows:

(a) **Statement of compliance and basis of measurement**

These financial statements are the representation of the Corporation`s management and are prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB). The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2020. The Corporation has adopted the requirements of IFRS 14 - Regulatory Deferral Accounts, which permits the Corporation to account for regulatory deferral account balances.

These financial statements have been prepared on a historical cost basis. These financial statements are presented in Canadian dollars and were approved by the Corporation's Board of Directors on March 26, 2021.

(b) **Effects of rate regulation**

The Ontario Energy Board (OEB) is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfil obligations to connect and service customers. The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate regulated corporation. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers in future periods through the rate-setting and approval process.

(c) **Cash and cash equivalents**

Cash and cash equivalents are defined as cash and highly liquid investments, consisting primarily of term deposits, with terms to maturity of three months or less at the date of purchase.

(d) **Inventory**

Inventory is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

2. **Significant accounting policies, continued**

(e) **Property, plant and equipment**

Property, plant and equipment are measured at historical cost less accumulated depreciation and impairment losses, if any. In circumstances where parts of an item of property, plant and equipment have different useful lives they are accounted for as separate components of property, plant and equipment. The Corporation provides for depreciation using the straight-line method at rates designed to depreciate the cost of the property, plant and equipment over their estimated useful lives. A full year's depreciation is recorded in the year of acquisition. No depreciation is recorded in the year of disposal. The carrying amount of an item of property, plant and equipment is derecognized on disposal. The annual depreciation rates and useful lives are reviewed annually and are as follows:

Buildings	50 years
Furniture and equipment	5-10 years
Vehicles	15 years
Transmission and distribution equipment	40-60 years

Construction in progress includes assets not currently in use and therefore not yet subject to depreciation.

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are classified as liabilities and are amortized at the same rate as the assets to which they relate.

2. **Significant accounting policies, continued**

(f) **Impairment of non-financial assets**

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit ("CGU") to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual CGUs, or otherwise they are allocated to the smallest group of CGUs for which a reasonable and consistent allocation basis can be identified.

Recoverable amount is the higher of fair value less costs to sell and value in use. 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 for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount. An impairment loss is recognized immediately in operations.

Where an impairment loss subsequently reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior years. A reversal of an impairment loss is recognized immediately in operations.

(g) **Goodwill**

Goodwill represents the difference between the acquisition cost of the Corporation and the fair value of the net assets acquired. Goodwill is not amortized, but is subject to fair value impairment tests annually. Goodwill is allocated to reporting units and any potential goodwill impairment is identified by comparing the carrying value of the reporting unit with its fair value. If any potential impairment is identified, then the amount of the impairment is quantified by comparing the carrying value of goodwill to its fair value, based on the fair value of the assets and liabilities of the reporting unit. Any impairment of goodwill is charged to operations in the period in which the impairment is determined.

(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 rate, net of tax, that reflects current market assessments of the time value of money and the risks specific to the liability.

2. **Significant accounting policies, continued**

(i) **Borrowing costs**

Borrowing costs directly attributable to the acquisition or construction of property, plant and equipment, which take a substantial period of time to get ready for their intended use, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use. All other borrowing costs are recognized in operations in the period in which they are incurred.

(j) **Asset retirement obligations**

Accounting standards require the Corporation to determine the fair value of future expenditures required to settle legal obligations to remove property, plant and equipment. If reasonably estimable, the Corporation recognizes a liability for the estimated current value of future expenditures required to settle obligations for the retirement of property, plant and equipment. Decommissioning liabilities are recorded at fair value, with a corresponding increase to the recorded amount of property, plant and equipment. Accretion of decommissioning liabilities are included in operations. Differences between the recorded amount of decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the period of settlement.

Some of the Corporation's distribution system assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of the related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

(k) **Pension plan**

The Corporation provides a pension plan for all its full-time employees through the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan that 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.

OMERS is a defined benefit plan, however it 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. Obligations for contributions to defined contribution pension plans are recognized as an expense in operations when they are due.

2. **Significant accounting policies, continued**

(l) **Revenue recognition**

Distribution and energy related revenues attributable to the supply and distribution of electricity are based on OEB approved rates and revenue is recognized as electricity is delivered to customers based on periodic meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available and no bills have been issued. This unbilled revenue is estimated and recorded in current assets on the statement of financial position at the end of each fiscal period. The related cost of energy is recorded on the basis of energy used.

The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers for energy sales based on regulated rates are recorded on the statement of financial position as regulatory assets and liabilities until their final disposition is decided by the OEB. In accordance with IFRS 14, the change in these regulatory assets and liabilities are reported, net of tax, with regulatory balances in the statement of comprehensive earnings.

Labour, rental and other charges revenue are recognized in the period in which these services are provided.

(m) **Payment in lieu of taxes**

Pursuant to the EA, the Corporation is required to compute taxes under the Income Tax Act (Canada) (ITA) and remit such amounts computed thereunder to the Ontario Electricity Financial Corporation (OEFC). These amounts, referred to as payments in lieu of taxes (PILs) under the EA, are applied to reduce certain debt obligations of the former Ontario Hydro now owing by the OEFC.

Payment in lieu of deferred income tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amount of assets and liabilities and their tax bases. Payment in lieu of deferred tax assets are also recognized for the benefit of any deductions or losses available to be carried forward to future periods for tax purposes that are likely to be realized. These amounts are measured using enacted or substantively enacted tax rates and are re-measured annually for changes in these rates. Any payment in lieu of deferred income tax assets are reassessed each fiscal period to determine if a valuation allowance is required. Any effect of the re-measurement or reassessment is recognized in operations in the period of the change.

As prescribed by regulatory rate order, payment in lieu of taxes are recovered through customer rates based on the taxes payable method. Therefore, rates do not include the recovery of payment in lieu of deferred taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, payment in lieu of deferred tax regulatory assets or liabilities are recognized for the amount of payment in lieu of deferred taxes which are expected to be included in future rates and recovered from or refunded to customers in future periods through the rate setting and approval process.

2. **Significant accounting policies, continued**

(n) **Employee future benefits**

The Corporation's net obligation in respect of its employee future benefit plan is calculated by estimating the amount of future benefits that employees have earned in return for their service in the current and prior periods, that benefit is discounted to determine its present value. Any unrecognised past service costs are deducted. The discount rate is the interest rate at the reporting date on high quality debt instruments with duration similar to the duration of the plan.

The cost of these employee future benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management's best estimate of certain underlying assumptions. Re-measurements arising from employee benefit plans are recognized immediately in operations. When the benefits of a plan are improved, these increases are recognized immediately in operations.

(o) **Financial instruments**

(i) **Measurement of financial instruments**

All of the Corporation's financial assets and financial liabilities are initially measured at fair value. Fair value is the amount for which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Transaction costs, that are directly attributable to the acquisition or issue of financial assets and financial liabilities, are added to the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition.

Subsequent to initial recognition these financial assets and financial liabilities are measured at their amortized cost. Amortized cost is the amount at which the financial instrument is measured at initial recognition less principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount. Interest rate swaps that are not hedging items are measured at fair value and changes in fair value are recognized in operations in the period they occur.

2. **Significant accounting policies, continued**

(o) **Financial instruments, continued**

(ii) **Impairment**

A financial asset measured at amortized cost is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount, and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in operations. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in operations.

(p) **Measurement uncertainty**

The preparation of financial statements in conformity with International Financial Reporting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. By their nature, these estimates are subject to measurement uncertainty. The effect of changes in such estimates on the financial statements in future periods could be significant, including changes as a result of future decisions made by the Ontario Energy Board (OEB). All estimates are reviewed periodically and adjustments are made and recognized in operations, as appropriate, in the period they become known. Accounts specifically affected by estimates and assumptions in these financial statements are as follows:

(i) **Property, plant and equipment**

Amounts recorded in the financial statements for depreciation are based on the estimated useful lives of the Corporation's property, plant and equipment. These useful lives are management's best estimate of the service lives of these assets and are reviewed annually. Changes to these estimated useful lives could materially affect the amount of depreciation recorded in the financial statements.

The Corporation's policy relating to property, plant and equipment is described in note 2(e). In applying this policy, management uses judgment in determining whether certain costs are additions to the carrying amount of property, plant and equipment or expensed in operations as repairs and maintenance. Judgment is also necessary in determining the appropriate componentization structure of the Corporation's property, plant and equipment.

2. **Significant accounting policies, continued**

(p) **Measurement uncertainty, continued**

(ii) **Payment in lieu of taxes**

Significant judgment is required in determining the provision for payment in lieu of taxes. There are many judgments and calculations made for which the ultimate tax determination is uncertain. The Corporation recognizes tax assets and liabilities based on the Corporation's interpretation of current tax law. Where the final outcome of these interpretations is different from the amounts that were originally recorded, these differences are recognized in the current and deferred income tax provisions in the period in which the determination is made.

(iii) **Employee future benefits**

The Corporation provides certain health and dental benefits to retired employees. The estimated cost of providing these benefits is accounted for on an accrual basis in the period in which employees render their services and are actuarially determined using the projected benefit method pro-rated on service and include management's best estimate of salary escalations, retirement ages and expected health care cost escalations.

(iv) **Regulatory assets and liabilities**

When recognizing regulatory assets and liabilities management assumes that such credits or costs will be recovered from customers or refunded to customers in future years through the rate setting and approval process. Refund or recovery of these regulatory assets and liabilities are subject to the review and approval of the OEB. Consequently, there is risk that some or all of the regulatory assets and liabilities will not be approved by the OEB which could have a material affect on the Corporation's comprehensive income in the year of the OEB decision.

3. **Future changes to significant accounting policies**

The Corporation's accounting policies are based on IFRS standards in effect on January 1, 2020. There are currently no IFRS standards that have been issued, but that are not yet effective, that would have a material affect on the Corporation's financial statements beginning on or after January 1, 2021.

4. **Accounts receivable**

	2020	2019
Electrical energy receivables	$ 909,972	$ 803,305
Other receivables	435,656	422,899
	$ 1,345,628	$ 1,226,204

	2020	2019
Aging of accounts receivable:		
Current	$ 1,212,093	$ 1,210,533
30 days	43,623	13,925
60 days	15,625	1,746
Over 90 days	74,287	-
	$ 1,345,628	$ 1,226,204

Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. Where the security posted is in the form of cash, these amounts are recorded on the statement of financial position as customer deposits.

Due to their short-term nature, the carrying amount of the accounts receivable and unbilled revenue approximates their fair value. Unbilled revenue reflects the electricity delivered but not yet billed to customers. Customer billings generally occur within 30 days of delivery. The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Corporation has approximately 3,700 customers, the majority of which are residential. The Corporation considers an account receivable to be in default when the customer is unlikely to pay its credit obligations in full, without recourse by the Corporation. Accounts are considered to be past-due when the customers have failed to make the contractually required payments when due, which is generally within 30 days of the billing date.

The Corporation considers an account receivable to be credit-impaired when the customer has amounts more than 90 days past the billing date. In determining the allowance for doubtful accounts, the Corporation considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances.

Customer deposits represents cash deposits from electricity distribution customers, retailers, and construction deposits. Deposits from electricity distribution customers are refundable to customers demonstrating 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 service.

The credit risk related to the Corporation’s accounts receivable has increased due to the impact and uncertainty of the COVID-19 pandemic, which has lead to slowing collections. The pandemic impact may effect the amount of cash collections related to accounts receivable balances into fiscal 2021 and could further impact the Corporation’s cash flow requirements.

5. Property, plant and equipment

2020

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of period	$ 88,880	183,831	5,354,183	385,981	47,995	59,631	$ 6,120,501
Additions	-	35,594	431,853	10,639	16,432	72,829	567,347
Transfers	-	-	42,074	-	-	(42,074)	-
Disposals	-	-	-	-	-	-	-
Balance, end of period	88,880	219,425	5,828,110	396,620	64,427	90,386	6,687,848
Accumulated Amortization							
Balance, beginning of period	-	27,231	787,716	133,468	26,971	-	975,386
Depreciation	-	4,631	174,199	27,340	4,112	-	210,282
Disposals	-	-	-	-	-	-	-
Balance, end of period	-	31,862	961,915	160,808	31,083	-	1,185,668
Net book value	$ 88,880	187,563	4,866,195	235,812	33,344	90,386	$ 5,502,180

2019

	Land	Buildings	Transmission & Distribution Equipment	Vehicles	Furniture and Equipment	Construction In Progress	Total
Cost							
Balance, beginning of period	$ 88,880	183,831	5,276,320	385,981	41,654	56,105	$ 6,032,771
Additions	-	-	77,863	-	6,341	3,526	87,730
Transfers	-	-	-	-	-	-	-
Disposals	-	-	-	-	-	-	-
Balance, end of period	88,880	183,831	5,354,183	385,981	47,995	59,631	6,120,501
Accumulated Amortization							
Balance, beginning of period	-	26,088	747,301	126,649	26,727	-	926,765
Depreciation	-	1,143	40,415	6,819	244	-	48,621
Disposals	-	-	-	-	-	-	-
Balance, end of period	-	27,231	787,716	133,468	26,971	-	975,386
Net book value	$ 88,880	156,600	4,566,467	252,513	21,024	59,631	$ 5,145,115

6. **Regulatory assets and liabilities**

	December 31, 2019	Regulatory activity	December 31, 2020
Settlement variance assets (a)	$ 1,327,910	$ 17,254	$ 1,345,164
Stranded meters (b)	9,052	(44)	9,008
Substation (c)	1,192,086	(143,645)	1,048,441
Payment in lieu of deferred tax regulatory assets (d)	167,980	(167,980)	-
Total regulatory assets	2,697,028	(294,415)	2,402,613
Settlement variance liabilities (a)	567,358	(289,887)	277,471
Payment in lieu of deferred tax regulatory liabilities (d)	-	151,790	151,790
Total regulatory liabilities	567,358	(138,097)	429,261
Net regulatory assets	$ 2,129,670	$ (156,318)	$ 1,973,352

	September 30, 2019	Regulatory activity	December 31, 2019
Settlement variance assets (a)	$ 1,492,061	$ (164,151)	$ 1,327,910
Stranded meters (b)	9,040	12	9,052
Substation (c)	1,223,160	(31,074)	1,192,086
Payment in lieu of deferred tax regulatory assets (d)	50,998	116,982	167,980
Total regulatory assets	2,775,259	(78,231)	2,697,028
Settlement variance liabilities (a)	442,463	124,895	567,358
Total regulatory liabilities	442,463	124,895	567,358
Net regulatory assets	$ 2,332,796	$ (203,126)	$ 2,129,670

6. Regulatory assets and liabilities, continued

In accordance with IFRS 14 - Regulatory Deferral Accounts, the Corporation has continued to apply the accounting policies that it applied, in accordance with CPA Canada Handbook Part V - pre-changeover accounting standards, prior to its adoption of International Financial Reporting Standards. Regulatory assets and liabilities arise as a result of the rate setting and approval process through the OEB.

(a) The difference between the amount paid by the Corporation to Hydro One for the purchase of energy and related service costs and the amount billed by the Corporation to its customers as energy sales, based on regulated rates, are recorded on the statement of financial position as settlement variance assets and liabilities until their final disposition is decided by the OEB. The Corporation recognizes settlement variances as an asset or liability based on the expectation that these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The settlement variance asset (liability) represents the excess (deficiency) of amounts billed to the Corporation by Hydro One for the purchase of energy over the amounts charged by the Corporation to its customers as energy sales. Currently, no amounts for settlement variances have been approved by the OEB for recovery or refund. Accordingly, the timing of the recovery or refund is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have increased by $307,141 (three month period ended December 31, 2019 - $289,046 decrease) related to amounts recognized for settlement variances.

(b) The stranded meter regulatory asset represents the unrecovered net book value of decommissioned analogue meters. At the direction of the OEB, the net book value of the stranded meters were reclassified to the regulatory asset account for recovery in rates to the end of March 2017. Currently, no amounts for stranded meters have been approved by the OEB for recovery. Accordingly, the timing of the recovery is unknown.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have decreased by $44 (three month period ended December 31, 2019 - $12 increase) related to amounts recognized for the stranded meters.

(c) The substation asset represents the cost of construction of a new substation in the Town of Espanola. The OEB approved the recovery for substation costs of $168,193 per year in the Corporation's rates until their next cost of service rate order.

In the absence of rate regulation, revenue recognized in the statement of comprehensive earnings (loss) would have decreased by $143,645 (three month period ended December 31, 2019 - $31,074 decrease) related to amounts recognized for the substation.

6. Regulatory assets and liabilities, continued

(d) The payment in lieu of deferred tax regulatory asset (liability) represents the expected increase (decrease) in distribution rates for customers arising from temporary differences which give rise to payment in lieu of deferred tax assets or liabilities. Currently, no amounts for payment in lieu of deferred taxes have been approved by the OEB for recovery or refund. Accordingly, the timing of the recovery is unknown.

For certain of the regulatory assets and liabilities, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund of each of its regulatory liabilities and continues to believe that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. Operating loan

A revolving operating loan credit facility has been granted by The Toronto Dominion Bank to a maximum of $750,000 (2019 - $500,000) bearing interest at the bank's prime rate of interest per annum.

This credit facility is secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited, a related company.

8. Advances from related company

The corporation is related to North Bay Hydro Distribution Limited by virtue of common controlling shareholders. The corporation is a wholly owned subsidiary of North Bay Hydro Holdings Limited.

	2020	2019
North Bay Hydro Distribution Limited	$ 704,196	$ 200,000

Included in accounts payable and accrued liabilities are amounts owing to North Bay Hydro Distribution Limited totalling $377,703 (2019 - $351,351).

The payables owing to and advances from North Bay Hydro Distribution Limited are unsecured, bear interest at the prime rate of interest per annum and have no specific terms of repayment. During the year interest of $38,909 was charged by North Bay Hydro Distribution Limited on these advances and is included in general and administration expense.

9. **Payment in lieu of taxes**

(a) The components of payment in lieu of deferred tax balances are as follows:

		2020		2019
Payment in lieu of deferred tax assets:				
Difference between tax basis of long-term obligations and carrying amount	$	213,625	$	12,365
Difference between tax basis of employee future benefits obligation and carrying amount		27,525		26,114
Carrying value of loss carry forward deferred tax asset		286,629		93,049
Payment in lieu of deferred tax liabilities:				
Difference between tax basis of property, plant and equipment and carrying amount		(375,989)		(299,508)
	$	151,790	$	(167,980)

(b) The provision for payment in lieu of taxes recorded in the financial statements differs from the amount which would be obtained by applying the statutory income tax rate of 26.5% (2019 - 26.5%) to the earnings (loss) for the periods as follows:

		2020		2019 (3 months)
Earnings (loss) for the period before payment in lieu of taxes, change in regulatory asset and liability balances and other comprehensive earnings (loss)	$	(1,200,622)	$	225,911
Change in regulatory asset and liability account balances related to profit and loss		163,452		(320,108)
Remeasurement of employee future benefits liability included in other comprehensive loss		(6,060)		-
	$	(1,043,230)	$	(94,197)
Anticipated income tax recovery	$	(276,456)	$	(24,962)
Tax effect of the following:				
Tax effect of change in regulatory assets		56,360		62,258
Tax effect of change in payment in lieu of deferred tax regulatory asset		(99,674)		11,252
Adjustment due to change in tax rate		-		68,434
Provision for (recovery of) payment in lieu of taxes	$	(319,770)	$	116,982

9. **Payment in lieu of taxes, continued**

(c) For payment in lieu of income tax purposes, the Corporation has losses carried forward from prior years which can be applied to reduce future years' taxable income. These losses expire as follows:

2037	$	351,128
2039		730,489
	$	1,081,617

Payment in lieu of deferred tax assets are recognised for tax losses carried forward only to the extent that realization of the related tax benefit is probable. At December 31, 2020 $286,629 (2019 - $93,049) related to available tax loss carry forwards, have been recognized as a payment in lieu of deferred tax asset.

In evaluating whether it is probable that taxable income will be earned in future years prior to any tax loss expiry, all available evidence was considered, including approved budgets, forecasts and rate changes. These forecasts are consistent with those prepared and used internally for business planning and impairment testing purposes. Following this evaluation, it was determined there would be sufficient taxable income generated to realize the benefit of the payment in lieu of deferred tax assets and that no reasonably possible change in any of the key assumptions would result in a material reduction in forecast taxable income so that the recognized payment in lieu of deferred tax asset would not be realized.

10. **Contributions in aid of construction**

In certain cases, non-refundable contributions are received in aid of construction or acquisition of property, plant and equipment. Contributions in aid of construction are deferred and amortized to other revenue at the same rate as the assets to which they relate.

		2020		2019 (3 months)
Balance, beginning of period	$	345,940	$	348,367
Contributions received in the period		5,147		100
Amortization of contributions in aid of construction		(7,711)		(2,527)
Balance, end of period	$	343,376	$	345,940

11. **Employee future benefits**

The Corporation pays certain post-employment health and dental benefits on behalf of its retired employees. Accounting standards for employee future benefits require that these post-retirement costs be recognized in the period in which the employees rendered their services. Information about the Corporation's accrued benefit obligation and the related expense are based on results and assumptions from a full actuarial valuation at December 31, 2018 and an update of the accounting extrapolations for the fiscal period ending December 31, 2020 and are as follows:

		2020		2019 (3 months)
Accrued benefit obligation, beginning of period	$	98,543	$	98,197
Current service cost recognized in operations		1,405		242
Interest cost recognized in operations		2,881		734
Benefits paid by employer		(5,022)		(630)
Net actuarial loss recognized in other comprehensive income		6,060		-
Accrued benefit obligation, end of period	$	103,867	$	98,543

The main assumptions employed for the valuation of the employee future benefit obligation are as follows:

The health benefit cost is estimated to increase at a rate of 4.2% (2019 - 4.0%) per annum. The dental benefit cost is estimated to increase at a rate of 4.5% (2019 - 4.3%) per annum.

The obligation at period-end and the present value of future obligations and the related expense, were determined using an annual discount rate of 2.6% per annum (2019 - 3.0%) representing an estimate of the yield on high quality corporate bonds with a duration similar to the duration of the plan.

Future general salary and wage levels were assumed, to increase at 2.5% (2019 - 2.5%) per annum.

12. **Long-term obligations**

	2020	2019
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $10,831 including interest at 3.78% per annum, maturing December 2040	$ 1,822,031	$ 1,881,898
Ontario Infrastructure and Lands Corporation non-revolving term loan, repayable in blended monthly installments of $2,860 including interest at 2.73% per annum, maturing December 2025	160,210	189,713
Toronto Dominion Bank committed reducing term facility by way of a floating rate term loan available by way of bankers acceptances, maturing October 2044	7,789,530	7,789,530
Toronto Dominion Bank committed reducing term facility by way of a fixed rate term loan, repayable in blending monthly payments of $2,351 including interest at 1.84% per annum, maturing September 2030	645,923	-
	10,417,694	9,861,141
Less current portion	108,952	89,370
	$ 10,308,742	$ 9,771,771

Estimated principal repayments are as follows:

2021	$ 108,952
2022	154,640
2023	373,418
2024	384,804
2025	396,606
Subsequent years	8,999,274
	$ 10,417,694

12. **Long-term obligations , continued**

The Ontario Infrastructure and Lands Corporation loans are secured by a general security agreement ranking behind the first ranking general security agreement registered by The Toronto Dominion Bank (note 7), an inter-creditor agreement between Ontario Infrastructure and Lands Corporation and The Toronto Dominion Bank and a guarantee provided by North Bay Hydro Distribution Limited.

The Corporation has entered into an interest rate swap derivative agreement with the Toronto Dominion Bank to manage the volatility of the interest rate on the committed reducing term facility. The loan is being repaid over 300 months with interest only repayments of $19,006 for 36 months until October 2022 then principal and interest repayments of $40,057 for 264 months until October 2044, with interest at a fixed rate of 2.928% per annum. The fair value of this loan is $8,595,663 (2019 - $7,836,190) which is estimated by obtaining mark-to-market quotes from the Toronto Dominion Bank resulting in an interest rate swap mark-to-market adjustment of $806,133 (2019 - $46,660). The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

The Toronto Dominion Bank committed reducing term facilities are secured by a general security agreement representing a first charge on all of the Corporation's present and after acquired property, an inter-creditor agreement with Ontario Infrastructure and Lands Corporation and a guarantee of advances by North Bay Hydro Distribution Limited.

The Ontario Infrastructure and Lands Corporation loans require the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:30 to 1 and a debt to total assets ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2023 fiscal period.

The Toronto Dominion Bank loan requires the Corporation at all times to meet a debt service coverage ratio of a minimum of 1:20 to 1 and a debt to capitalization ratio of less than 60% calculated annually at December 31st beginning with the December 31, 2022 fiscal period.

13. **Share capital**

		2020		2019
Authorized				
Unlimited number of common shares				
Issued				
100 common shares	$	100	$	100

14. **Operating expenses**

For internal management reporting purposes the Corporation's operating expenses are reported by function. Operating expenses reported by object are as follows:

		2020		2019 (3 months)
Salaries, wages and benefits	$	619,045	$	150,617
Contracted services		447,661		107,785
General and administration		339,335		108,270
Operations and maintenance		114,087		43,108
Depreciation		210,282		48,621
Bad debts (recovery)		14,557		(4,911)
	$	1,744,967	$	453,490

15. Change in non-cash working capital items

		2020	2019 (3 months)
Accounts receivable	$	(119,424) $	24,051
Unbilled revenue - energy sales		22,249	(509,697)
Unbilled revenue - distribution		3,266	(42,362)
Inventory		(10,198)	(3,844)
Prepaid expenses		(425,951)	23,678
Payment in lieu of taxes paid		1,816	(2)
Accounts payable and accrued liabilities		503,933	(1,008,292)
Payable for energy purchases		(70,114)	675,874
	$	(94,423) $	(840,594)

16. Pension plan

The Corporation provides pension benefits to its employees through the Ontario Municipal Employees Retirement System (OMERS) pension plan. The plan is a multi-employer, contributory, defined benefit pension plan funded by equal contributions by both employer and employees. During the period the Corporation made employer contributions of $47,703 (three month period ended December 31, 2019 - $14,908) to OMERS.

At December 31, 2020 the OMERS pension plan had total assets of $122.5 billion (2019 - $121.8 billion) and an accumulated deficit of $8.632 billion (2019 - $765 million surplus).

17. Commitments

The Corporation has entered into a contract for management, billing, collecting, customer service, software and data hosting services and support with PUC Services Inc. expiring February 28, 2022 at a base cost as follows:

2021	$	180,958
2022		30,408
	$	211,366

In addition to the above charges, a monthly charge of $5.53 to $5.75 per meter, for up to 3,700 meters for residential and general service customers, will also apply.

18. Capital disclosure

The Corporation's objectives when managing capital are:

(a) Ensure ongoing access to capital at a reasonable cost in order to maintain and improve the electricity distribution system of the Corporation to ensure the continued delivery of safe, reliable electricity services to customers, and to safeguard the Corporation's ability to continue as a going concern and provide a reasonable rate of return to its shareholders;

(b) Maintain the Corporation's capital structure with the financial ratios and recommended guidelines prescribed by the OEB.

The Corporation's capital consists of its common share capital, retained earnings (deficit) operating loans, advances from related company and long-term obligations. In order to achieve the above noted objectives the Corporation develops detailed annual operating and capital budgets and seeks to control costs to meet its working capital and capital investment requirements on both a short-term and long-term basis. There have been no changes in the Corporation's approach to managing capital during the period.

At December 31, 2020 the Corporation is party to debt agreements with Ontario Infrastructure and Lands Corporation (note 12) and The Toronto Dominion Bank (notes 7 and 12) that contain certain covenants that restrict the Corporation from incurring additional debt or making distributions to shareholders in excess of certain limits, that would cause a violation of those covenants.

19. Financial instruments

Transactions in financial instruments may result in an entity assuming or transferring financial risks to or from another party. The Corporation is exposed to the following risks associated with financial instruments and transactions it is a party to:

(a) Fair value

The fair value of current financial assets and current financial liabilities approximates their carrying value due to their short-term maturity dates. The fair value of long-term financial liabilities approximates their carrying value based on the presumption that the Corporation is a going concern and thus expects to fully repay the outstanding amounts. Fair value of derivative financial instruments is estimated by obtaining mark-to-market quotes from The Toronto Dominion Bank. The quoted amount reflects the estimated amount that the Corporation would pay to settle the derivative agreement at the statement of financial position date.

19. **Financial instruments, continued**

(b) Credit risk

Credit risk is the risk that one party to a financial transaction will fail to discharge a financial obligation and cause the other party to incur a financial loss. The Corporation's main credit risks are associated with its cash and accounts receivable.

The Corporation minimizes credit risk associated with its cash balances by ensuring that these financial assets are held with large reputable financial institutions with high credit ratings.

The Corporation incurs amounts due from its customers in the regular course of business and has credit risk associated with its accounts receivable balances of $2,268,533 (2019 - $2,174,624). The Corporation reduces its exposure to credit risk through management's on-going monitoring of its accounts receivable balances and collections. Credit valuations are performed on a regular basis and credit is granted upon a review of the credit history of the applicant. An allowance for bad debts is recorded when applicable.

(c) Liquidity risk

Liquidity risk is the risk that the Corporation cannot repay its obligations when they become due to its creditors. The Corporation has liquidity risk associated with its operating loan, accounts payable and accrued liabilities, payable for energy purchases and long-term obligations. The Corporation reduces its exposure to liquidity risk by ensuring that it documents when authorized payments become due, and budgets to maintain adequate cash resources including an operating line of credit, to repay creditors including long-term obligations interest and principal as those liabilities become due.

With the exception of the amounts included in accounts payable and accrued liabilities owing to North Bay Hydro Distribution Limited (note 8) the majority of the Corporation's accounts payable and payable for energy purchases, as reported in the statement of financial position, are due within 30 days.

20. Uncertainty due to COVID-19

The assessment of the duration and severity of the developments related to the COVID-19 pandemic continue to be subject to significant uncertainty. The company has developed guidelines for its workforce that align with the Provincial Framework and prioritize the safety of employees, customers, and the public. These guidelines enable the company to pivot to appropriate work protections depending on the various orders that the local and provincial health authorities issue. The local and provincial directives have the ability to halt all non-essential work; the company provides an essential service to the community and work in the public domain continues under the above-mentioned guidelines and administrative staff have been transitioned to a work from home approach.

The pandemic has affected customers in different ways. Residential consumption has increased and the commercial and industrial customer base has seen a decrease in demand on the system, however, the continued impact of the pandemic on customer energy needs is difficult to predict and quantify. The pandemic can affect supply chains (delays, constraints, cost increases) and the collectability of accounts receivable; these areas of the business continue to be monitored and managed closely by the company, however, they are subject to continued uncertainty. At this time, the future impact of COVID-19 on the entity cannot be known with certainty.

Appendix F

Proforma Financial Statements of New NBHDL

New North Bay Hydro Distribution Ltd.
Pro-forma Income Statement
Fiscal Period 2023

	2023
Electricity Sales	85,880,388
Other Revenue	1,025,292
Total Revenue	**86,905,680**
Cost of Power	69,669,100
Operating Expenses	
Operations & Maintenance	4,621,560
Billing, Collecting & Administration	4,375,769
Depreciation and Amortization, Disposals	3,977,327
Total Operating Expenses	**82,643,755**
Income from Operating activities	**4,261,925**
Finance Income	302,479
Finance Costs	1,546,050
Other Income / (Expenses)	(15,000)
Income before provision for PILs	**3,003,354**
Income Tax	117,321
Net Income	**2,886,033**

New North Bay Hydro Distribution Ltd.
Pro-forma Balance Sheet
Fiscal Period 2023

	2023
<u>ASSETS</u>	
Current assets	
Cash and short-term investments	7,904,711
Accounts receivable	18,826,953
Inventory	769,049
Other	678,621
Total current assets	**28,179,334**
Non-current Assets	
Property, plant and equipment	91,101,704
Goodwill	3,322,007
Other Assets	3,350,696
Regulatory deferral account debit balances	2,926,690
TOTAL ASSETS	**128,880,432**
<u>LIABILITIES</u>	
Current liabilities	
Accounts payable and accrued liabilities	13,152,684
Current portion of long-term debt	6,624,051
Total current liabilities	**19,776,735**
Long-term liabilities	
Customer deposits	840,312
Contributed capital / deferred revenue	6,052,354
Employee future benefits	4,937,972
Long-term debt	49,380,989
Financial Instrument Liability	2,395,531
Regulatory deferral account credit balances	2,218,759
Total long-term liabilities	**65,825,916**
<u>SHAREHOLDER'S EQUITY</u>	
Capital Stock	19,511,701
Retained earnings	23,766,079
Total shareholder's equity	**43,277,780**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**128,880,432**

New North Bay Hydro Distribution Ltd.
Statement of Cash Flows
Fiscal Period 2023

	2023
OPERATING ACTIVITIES	
Net Income	2,886,033
Net adjustments to non-cash charges & working capital balances	1,325,067
Net cash flows from operating activities	**4,211,100**
INVESTING ACTIVITIES	
Purchase of property, plant and equipment	(5,745,583)
Changes in regulatory deferral account balances	(24,823)
Cash used in investment activities	**(5,770,406)**
FINANCING ACTIVITIES	
Long term debt	(150,659)
Dividends	(874,052)
Cash provided by financing activities	**(1,024,711)**
Net increase in cash	(2,584,017)
Cash at beginning of year	10,488,728
Cash, end of the period	**7,904,711**

Appendix G

2021 OEB-approved rate riders for ERHDC and NBHDL

North Bay Hydro Distribution Limited
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2021
Implementation Date October 1, 2021
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2020-0043

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.64
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	1.44
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until September 30, 2022	$	0.04
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$	(1.53)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Low Voltage Service Rate	$/kWh	0.00015
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0008
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0069

MONTHLY RATES AND CHARGES - Regulatory Component

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

North Bay Hydro Distribution Limited
TARIFF OF RATES AND CHARGES
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Implementation Date October 1, 2021
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EB-2020-0043

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification includes non residential accounts taking electricity at 750 volts or less where monthly average peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	26.84
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	0.77
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0206
Low Voltage Service Rate	$/kWh	0.00014
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kWh	0.0007
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kWh	(0.0002)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$/kWh	(0.0015)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until September 30, 2022	$/kWh	0.0010
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kWh	0.0006
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

MONTHLY RATES AND CHARGES - Regulatory Component

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

North Bay Hydro Distribution Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date October 1, 2021

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EB-2020-0043

GENERAL SERVICE 50 TO 2,999 KW SERVICE CLASSIFICATION

This classification includes non residential accounts where monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to Wholesale Market Participant (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	345.89
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	12.56
Distribution Volumetric Rate	$/kW	2.8704
Low Voltage Service Rate	$/kW	0.05359
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	0.1090
Rate Rider for Group 1 Disposition of Deferral/Variance Accounts - effective until September 30, 2022	$/kW	0.0178
Rate Rider for Group 2 Disposition of Deferral/Variance Accounts - effective until September 30, 2022	$/kW	(0.3241)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until September 30, 2022	$/kW	0.2970
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kW	0.0977
Retail Transmission Rate - Network Service Rate	$/kW	3.2616

North Bay Hydro Distribution Limited
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Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.4190

MONTHLY RATES AND CHARGES - Regulatory Component

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

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GENERAL SERVICE GREATER THAN 3,000 KW SERVICE CLASSIFICATION

This classification includes non residential accounts where monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than 3,000 kW. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to Wholesale Market Participant (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,228.64
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	206.03
Distribution Volumetric Rate	$/kW	1.2846
Low Voltage Service Rate	$/kW	0.05923
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2020) - effective until October 31, 2021	$/kW	0.3146
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	0.0038
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	(0.3473)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) (2021) - effective until September 30, 2022	$/kW	0.2215
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kW	0.0195
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.4598

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Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.6732

MONTHLY RATES AND CHARGES - Regulatory Component

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

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification includes accounts taking electricity at 750 volts or less where monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. These connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.94
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	0.17
Distribution Volumetric Rate	$/kWh	0.0136
Low Voltage Service Rate	$/kWh	0.00014
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$/kWh	(0.0015)
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0082
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0061

MONTHLY RATES AND CHARGES - Regulatory Component

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

North Bay Hydro Distribution Limited
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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.47
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	0.15
Distribution Volumetric Rate	$/kW	19.0942
Low Voltage Service Rate	$/kW	0.04143
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	0.0981
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	(4.4870)
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kW	0.5442
Retail Transmission Rate - Network Service Rate	$/kW	2.4720
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.9089

MONTHLY RATES AND CHARGES - Regulatory Component

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

North Bay Hydro Distribution Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date October 1, 2021

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EB-2020-0043

STREET LIGHTING SERVICE CLASSIFICATION

This classification is for roadway lighting with the Municipality. The consumption for this customer is based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.41
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$	(1.52)
Distribution Volumetric Rate	$/kW	7.5730
Low Voltage Service Rate	$/kW	0.04229
Rate Rider for Disposition of Group 1 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	0.4798
Rate Rider for Disposition of Group 2 Deferral/Variance Accounts - effective until September 30, 2022	$/kW	(1.1270)
Rate Rider for Recovery of 2021 Foregone Revenue - effective until September 30, 2022	$/kW	(8.1590)
Retail Transmission Rate - Network Service Rate	$/kW	2.4600
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.8698

MONTHLY RATES AND CHARGES - Regulatory Component

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

North Bay Hydro Distribution Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date October 1, 2021

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

EB-2020-0043

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

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

North Bay Hydro Distribution Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date October 1, 2021

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EB-2020-0043

SPECIFIC SERVICE CHARGES

APPLICATION

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

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

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

Customer Administration

Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	165.00

Other

Service call - customer owned equipment	$	30.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	44.50

North Bay Hydro Distribution Limited

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date October 1, 2021

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EB-2020-0043

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

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

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

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

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.17
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.08

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0389
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0285

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accomodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Further servicing details are available in the distributor's Conditions of Serivce.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	21.70
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	1.53
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$	(2.07)
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0184
Low Voltage Service Rate	$/kWh	0.0067
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0022
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kWh	0.0006
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0002
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricty at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	31.66
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	1.29
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0260
Low Voltage Service Rate	$/kWh	0.0060
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0022
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0021)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kWh	0.0015
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose average peak demand is greater than, or is forecast to be greater than 50 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	196.43
Distribution Volumetric Rate	$/kW	4.6411
Low Voltage Service Rate	$/kW	2.3267
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8239
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kW	(0.3609)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kW	0.2591
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kW	2.5889

Espanola Regional Hydro Distribution Corporation
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Effective Date May 1, 2021
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EB-2020-0020

Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7589
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.9103
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.4365

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricty at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	15.42
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	0.63
Distribution Volumetric Rate	$/kWh	0.0197
Low Voltage Service Rate	$/kWh	0.0060
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kWh	0.0024
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0028)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kWh	(0.0006)
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2021
Implementation Date July 1, 2021
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EB-2020-0020

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Serivce customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.39
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	0.25
Distribution Volumetric Rate	$/kW	27.3183
Low Voltage Service Rate	$/kW	1.8361
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8173
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kWh	(0.0061)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kW	(0.5741)
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	0.0056
Retail Transmission Rate - Network Service Rate	$/kW	1.9623
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3880

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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

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

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.27
Rate Rider for Recovery of (2021) Foregone Revenue Fixed - Rates Effective May 1, 2021 - effective until April 30, 2022	$	(0.28)
Distribution Volumetric Rate	$/kW	15.9433
Low Voltage Service Rate	$/kW	1.7986
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2026	$/kW	0.8614
Rate Rider for Disposition of Global Adjustment Account - effective until April 30, 2022 - Applicable for only Non-RPP Customers	$/kWh	0.0050
Rate Rider for Group 2 Accounts - Pole Attachment Variance and CCA - effective until April 30, 2022	$/kW	(1.7862)
Rate Rider for Disposition of Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) - effective until April 30, 2026	$/kW	33.7000
Rate Rider for Recovery of (2021) Foregone Revenue Variable - Rates Effective May 1, 2021 - effective until April 30, 2022	$/kWh	(0.0054)
Retail Transmission Rate - Network Service Rate	$/kW	1.9526
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3596

MONTHLY RATES AND CHARGES - Regulatory Component

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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EB-2020-0020

microFIT SERVICE CLASSIFICATION

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

APPLICATION

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

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

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

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

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

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

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

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EB-2020-0020

SPECIFIC SERVICE CHARGES

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

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

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

Customer Administration

Arrears certificate	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at Meter - during regular hours	$	65.00
Reconnection at Pole - during regular hours	$	185.00

Other

Temporary service - install & remove - overhead - no transformer	$	500.00
Temporary service - install & remove - underground - no transformer	$	300.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments) - Approved on an Interim Basis	$	44.50

Espanola Regional Hydro Distribution Corporation

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2021

Implementation Date July 1, 2021

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

EB-2020-0020

RETAIL SERVICE CHARGES (if applicable)

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

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

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

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

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	104.24
Monthly Fixed Charge, per retailer	$	41.70
Monthly Variable Charge, per customer, per retailer	$/cust.	1.04
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.62
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.62)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.52
Processing fee, per request, applied to the requesting party	$	1.04
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.17
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.08

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0673
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0567