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**Frank D'Andrea**
Vice President, Regulatory Affairs & Chief Risk Officer

BY EMAIL, COURIER, RESS

October 25, 2019

Ms. Christine E. Long
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long,

**EB-2018-0275 – Niagara Reinforcement Limited Partnership's 2020-2024 Transmission Revenue Cap IR Application and Evidence Filing**

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Hydro One Networks Inc., on behalf of Niagara Reinforcement Limited Partnership ("NRLP"), has submitted a five-year Transmission Revenue Cap IR Application for the period 2020-2024 and prefiled evidence in support of the Application, using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System.

Given that NRLP operates a single transmission asset, with minimal operating costs and no forecast capital expenditures, Hydro One proposes that this Application would be most effectively dealt with in written form. Moreover, Hydro One encourages the OEB to make provision for a Settlement conference to assist with the expediency of the application.

NRLP will post electronic copies of the Application and supporting evidence on the internet for public access. A text-searchable Adobe Acrobat electronic version and two paper copies of the Application will be sent to the OEB shortly.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

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# APPLICATION

## ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15;

AND IN THE MATTER OF an Application by Niagara Reinforcement Limited Partnership by its general partner, Hydro One Indigenous Partnerships GP Inc. ("HOIP"), for an Order or Orders made pursuant to section 78 of the Act approving rates for the transmission of electricity.

1. The applicant, Niagara Reinforcement Limited Partnership ("NRLP"), is a Limited Partnership. Through subsidiary entities where applicable or otherwise, the partnership interests are held by
    - HOIP, the general partner
    - Hydro One Networks Inc. ("HONI"), a limited partner,
    - Six Nations of the Grand River Development Corporation, a limited partner, and,
    - Mississaugas of the Credit First Nation.

2. NRLP has its head office in Markham, Ontario, and is licensed by the Ontario Energy Board (the "OEB"), under licence number ET-2018-0277, to transmit electricity. NRPL carries on the business of owning and operating transmission facilities in Ontario.

3. This is an application for a Revenue Cap Index framework covering a five-year test period commencing January 1, 2020, and ending December 31, 2024 (the "Application").

4. NRLP hereby applies to the Ontario Energy Board (the "OEB" or the "Board"), pursuant to Section 78 of the *Ontario Energy Board Act, 1998*, for an Order or Orders approving:
    a) NRLP's total revenue requirement for the 2020 Test Year, determined by using a cost of service, forward test-year approach;
    b) An amendment to Ontario's Uniform Transmission Rates for the Network pool to allow for the recovery of NRLP's proposed rates revenue requirement for 2020, to be effective and implemented on January 1, 2020;
    c) The proposed Revenue Cap Index mechanism to set NRLP's transmission revenue requirement and Uniform Transmission Rates for the Network pool for the period effective January 1, 2021, through December 31, 2024, as described in Exhibit A, Tab 4, Schedule 1;
    d) The establishment and approval of the accounting orders for an Earnings Sharing Mechanism Deferral Account effective January 1, 2020, as described in Exhibit H, Tab 1, Schedule 1;
    e) The continuation of the NRP Transmission Line Revenue Requirement Deferral Account ("NRLPDA") effective September 1, 2019 as described in Exhibit H, Tab 1, Schedule 1;
    f) The recovery of the prudently costs incurred during the period of September 1, 2019 to December 31, 2019 logged in the deferral account ("NRLPDA") that was established pursuant to the decision issued by the Board on September 26, 2019;
    g) Other items or amounts that may be requested by NRLP in the course of this proceeding, and as may be granted by the OEB.

5. This application has been prepared in accordance with the OEB's *Filing Requirements for Electricity Transmission Rate Applications* dated February 11, 2016.

6. The written evidence filed with the OEB may be amended from time to time prior to the OEB's final decision on the Application.

7. NRLP may seek meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

**NOTICE AND FORM OF HEARING REQUESTED**

8. NRLP operates a transmission line in Ontario that benefits customers across the province. Notice of this Application should be published so as to reach the largest number of customers across Ontario in an efficient manner.

9. The persons affected by this Application are the ratepayers of the transmission system in Ontario. It is impractical to set out their names and addresses because they are too numerous.

10. The Application may be viewed on the Internet at the following address: http://www.hydroone.com/NRLP

11. NRLP requests that this Application be heard by way of a written hearing.

**PROPOSED EFFECTIVE DATE**

12. NRLP requests that the OEB's rate orders be made effective January 1, 2020. To address the possibility that the requested rate orders cannot be made effective by that time, NRLP requests an interim Order making its proposed transmission revenue requirement effective on an interim basis as of January 1, 2020, and allowing NRLP to use the existing NRLPDA to record any differences in the revenue requirement between the interim Order and the final approved Decision and Order. Any balance

will be collected and submitted at a future proceeding such as the end of 2020 update for 2021 rates.

**CONTACT INFORMATION**

NRLP requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) For the Applicant:

Ms. Linda Gibbons
Senior Regulatory Coordinator – Regulatory Affairs
Hydro One Networks Inc.

| | |
|---|---|
| Address for personal service: | 7th Floor, South Tower<br>483 Bay Street<br>Toronto, ON M5G 2P5 |
| Mailing Address: | 7th Floor, South Tower<br>483 Bay Street<br>Toronto, ON M5G 2P5 |
| Telephone: | (416) 345-4373 |
| Fax: | (416) 345-5395 |
| Electronic access: | Regulatory@HydroOne.com |

b) The Applicant's counsel:

Michael Engelberg
Assistant General Counsel
Hydro One Networks Inc.

| | |
|---|---|
| Address for personal service: | 8th Floor, South Tower<br>483 Bay Street<br>Toronto, ON M5G 2P5 |
| Mailing Address: | 8th Floor, South Tower<br>483 Bay Street<br>Toronto, ON M5G 2P5 |
| Telephone: | (416) 345-6305 |
| Fax: | (416) 345-6972 |
| Electronic access: | mengelberg@HydroOne.com |


DATED at Toronto, Ontario, this 25th day of October 2019

by NIAGARA REINFORCEMENT LIMITED PARTNERSHIP
By its counsel,

ORIGINAL SIGNED BY MICHAEL ENGELBERG

___________________________________

Michael Engelberg

# CERTIFICATION OF EVIDENCE

Niagara Reinforcement Limited Partnership
A limited partnership under the laws of Ontario
(hereinafter, "NRLP")

TO: THE ONTARIO ENERGY BOARD

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The undersigned, Jeffrey Smith, hereby certifies for and on behalf of NRLP that:

1. I am the Managing Director of Hydro One Indigenous Partnerships GP Inc., the General Partner for NRLP;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's Filing Requirements for Electricity Transmission Applications (last revised on February 11, 2016); and
3. The evidence submitted in support of NRLP's 2020 revenue requirement application (EB-2018-0275) filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

DATED: October 25, 2019

ORIGINAL SIGNED BY JEFFREY SMITH

____________________________________

Jeffrey Smith
for NRLP by its General Partner, Hydro One Indigenous Partnerships GP Inc.

Witness: Jeffrey Smith

# COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY TRANSMITTERS

NRLP has prepared this Application in alignment with the OEB's guidance in its *Filing Requirements for Electricity Transmission Rate Applications* (February 11, 2016) ("Transmission Filing Requirements"). NRLP has presented the content to align with Chapter 2 of the Transmission Filing Requirements ("Chapter 2"). To assist the OEB in its review of the Application, NRLP has prepared a checklist of the Transmission Filing Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1 to this Exhibit.

Given the unique nature of the NRLP's assets and the role they play in the transmission of electricity in the province, a number of Transmission Filing Requirements are not applicable. These include:

1. **Customer Engagement**
    - NRLP does not have any direct customers, and hence has not performed any customer engagement activities and analysis.

2. **Transmission System Plan**
    - NRLP has prepared an abridged Transmission System Plan ("TSP") given that it is not proposing capital expenditures during the rate period. Moreover, NRLP did not undertake a capital expenditure planning process, or participate in a regional planning process. NRLP has not provided external cost benchmarking, justification for capital expenditures, or details on material investments as none are included in this Application.

- Section 2.4 of Chapter 2 states that transmitters may wish to refer to Chapter 5 of the OEB's Filing Requirements for Electricity Distributors, Consolidated Distribution System Plan Filing Requirements ("DSP Requirements") for further guidance on the content and structure of a TSP. NRLP has adopted the DSP Requirements to guide the preparation of its abridged TSP. NRLP has prepared a checklist of the DSP Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1.

**3. Working Capital Allowance**

- In B2M LP's previous transmission rates application (EB-2015-0026), it was established and that there is no need for a working capital allowance given the that timing of the payments and revenue could be organised by the General Partner to effectively ameliorate any meaningful lead or lag on those cash flows. The same situation applies for NRLP and therefore these is no request for a working capital allowance to be included in rate base.

**4. Economic Overview / Load Forecast**

- NRLP's asset base consists of one 230 kV transmission line comprised of two circuits with no delivery points. Hence, NRLP has no discrete, incremental load determinants to include in the UTR forecast.
- The only rate pool applicable for NRLP assets is the "Network" pool. Therefore, no further cost allocation methodology is presented in this application.

### 5. Other Revenue

- NRLP has no external revenue sources, the only revenue applicable to NRLP is the revenue requirement from owning and maintaining its 230 kV transmission line.

### 6. Employee Compensation

- NRLP has no employees. Operations and management services are provided by Hydro One by a service level agreement as outlined in Exhibit F, Tab 3, Schedule 1.

Where applicable, NRLP has incorporated the Chapter 2 appendices from the *Filing Requirements for Electricity Distributors* to support its evidence. These are listed in Attachment 1 to this Exhibit and are provided throughout the Application.

In preparing this Application, NRLP followed the expectations of a Revenue Cap Index application provided in the Transmission Filing Requirements:

**Term:** 5 years (rebasing plus 4 years)

**Index for the Annual Rate Adjustment:** The proposed Revenue Cap Index includes an industry-specific inflation factor and a productivity factor as outlined in Exhibit A, Tab 4, Schedule 1.

**Benchmarking**: Operations and management services are provided to NRLP through a service level agreement with Hydro One Networks Inc. These types of activities are subject to review through Hydro One Networks Inc.’s external benchmarking evidence provided in its transmission rate applications.

**Performance Metrics:** NRLP proposes to track its performance utilizing a set of outcome measures as documented in Exhibit D, Tab 1, Schedule 1 to ensure that NRLP meets its five year plan. The proposed metrics align with the RRF outcomes of operational effectiveness, financial performance and public policy responsiveness.[1]

**Updates:** NRLPs proposal contains an update in 2021 to align its cost of long-term debt with the actual market rate of its debt refinancing as documented in Exhibit G, Tab 1, Schedule 1.

**Protecting Customers:** Exhibit A, Tab 4, Schedule 1 outlines NRLP's proposed Earnings Sharing Mechanism which shares the benefit of productivity improvements with customers during the term and provides rate payers with protection from utility earnings that may exceed proposed levels.

[1] Customer Focus has been excluded as NRLP does not have any direct customers.

# Transmission Filing Requirements Checklist

## NRLP

**Date: February 11, 2016**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **GENERAL REQUIREMENTS** | | | |
| Ch 1, p 2 | Certification that the evidence filed is accurate, consistent and complete | Yes | Exhibit A, Tab, 2, Schedule 1, Attachment 1 |
| 3 | Confidential Information - Practice Direction has been followed | Yes | |
| Ch 2, p 4 | Provide Chapter 2 appendices that are applicable to transmission applications<br>*Not applicable:*<br>*2-AC on Customer Engagement, 2-G SQI, 2-H Other Operating Reve, 2-I/2-IA/2-IB Load Forecast/CDM, 2-JC OMA Programs, 2-K Employee Costs, 2-N OMA/FTE* | Yes | 2-AA/2-AB Capital Program/Expenditures: Exhibit B, Tab 1, Schedule 3, Attachment 1 |
| 4 | Written direct evidence is to be included before data schedules | Yes | |
| 4 | Average of the opening and closing fiscal year balances must be used for items in rate base | Yes | Exhibit C, Tab 1, Schedule 1 |
| 4 | Total capitalization (debt and equity) must equate to total rate base | Yes | Exhibit G, Tab 1, Schedule 1 and Exhibit C, Tab 1, Schedule 1 |
| 4 | Data for the following years, at a minimum, must be provided: Test year = prospective rate year; Bridge year = current year; Four most recent historical years; Most recent OEB-approved test year | Yes | |
| 4 | *Not applicable: Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts* | N/A | Revenue Cap IR Proposed |
| 4 | Documents are to be provided in bookmarked and text-searchable Adobe PDF format | Yes | |
| 4 | Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical | Yes | |
| 6 | Materiality threshold | Yes | |
| 6 | State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing | Yes | Exhibit A, Tab 6, Schedule 1 |

| EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS | | | |
|---|---|---|---|
| *Executive Summary* | | | |
| Ch 2, p 8 | Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives | Yes | Exhibit A, Tab 3, Schedule 1 |
| 8 | Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE including<br>*Not applicable: customer feedback reflected in the transmitter's objectives* | Yes | Exhibit A, Tab 3, Schedule 1 |
| 8 | Revenue Requirement - request, changes from previous revenue requirement and drivers of change | Yes | Exhibit A, Tab 3, Schedule 1 |
| 8 | Budgeting Assumptions - Economic overview<br>*Not applicable: no capital expenditures* | No | Exhibit A, Tab 3, Schedule 1 |
| ~~8~~ | *Not applicable: Load Forecast - Load growth and forecast methods* | No | Exhibit A, Tab 3, Schedule 1 |
| ~~9~~ | TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Rate Base - Request for test years and change from last OEB approved | Yes | Exhibit A, Tab 3, Schedule 1 |
| ~~9~~ | Performance and Reporting - Proposed scorecard<br>Reporting limited to the 5 metrics in the EB-2015-0026 Decision | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | OM&A - Request for test years, changes from last OEB approved and drivers of change | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology | Yes | Exhibit A, Tab 3, Schedule 1 |
| 9 | Cost Allocation + Rate Design - Summary of how costs are allocated to rate pools | Yes | Exhibit A, Tab 3, Schedule 1 |
| 10 | Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts | Yes | Exhibit A, Tab 3, Schedule 1 |
| 10 | Bill Impacts - Summary of impacts at wholesale level and for typical retail customers | Yes | Exhibit A, Tab 3, Schedule 1 |
| *Customer Engagement* | *Not applicable: NRLP has no customers* | | |
| Ch 2, p 10 | Customer engagement process and activities | N/A | |
| 10 | Customer needs including end-use load customers and generator customers | N/A | |
| 10 | How the application responds to customer needs | N/A | |
| 10 | Customer satisfaction surveys | N/A | |
| 10 | Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence | N/A | |
| 11 | Responses to letters of comment | N/A | |

| | | | |
|---|---|---|---|
| *Financial Information* | | | |
| Ch 2, p 11 | Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals) | Yes | Exhibit A, Tab 6, Schedule 2 |
| 11 | Detailed reconciliation of AFS with regulatory financial results | Yes | Exhibit A, Tab 6, Schedule 3 |
| 11 | Annual Report and MD&A for most recent year of parent company | Yes | Exhibit A, Tab 6, Schedule 4 |
| 11 | Rating Agency Reports: NR*LP Debt is managed and rated under Hydro One Networks* | N/A | EB-2019-0082: Exhibit A, Tab 6, Schedule 3 |
| 11 | Prospectuses & information circulars for recent and planned public offerings: NRLP Debt is managed and rated under Hydro One Networks | N/A | EB-2019-0082: Exhibit A, Tab 6, Schedule 5 |
| *Administration* | | | |
| Ch 2, p 11 | Table of Contents | Yes | Exhibit A, Tab 1, Schedule 1 |
| 11 | Statement identifying customers materially affected by the application | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Internet address for viewing of application | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Primary contact information (name, address, phone, fax, email) | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Identification of legal representation | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Requested effective date | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Bill impacts for typical Ontario residential customer an Ontario General Service customer | Yes | Exhibit A, Tab 3, Schedule 1 |
| 12 | Form of hearing requested (written or oral) | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | List of approvals requested including accounting orders | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Proposed length of the term and proposed method for establishing revenue requirement for each year of the term | Yes | Exhibit A, Tab 2, Schedule 1 |
| 12 | Changes in tax status | Yes | Exhibit A, Tab 6, Schedule 1 |
| 12 | Existing Accounting Orders | Yes | Exhibit H, Tab 1, Schedule 1 |
| 12 | Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility. | Yes | Exhibit B, Tab 1, Schedule 1 |
| 12 | Corporate and utility organizational structure, planned changes, rationale for changes and cost impact | Yes | Exhibit A, Tab 5, Schedule 1 |
| 13 | The Accounting Standard used and when it was adopted | Yes | Exhibit A, Tab 6, Schedule 1 |
| 13 | Deviations from filing requirements, if any | N/A | |
| 13 | Changes to methodologies used in previous applications | Yes | Exhibit A, Tab 6, Schedule 1 |
| 13 | Confirmation that accounting treatment is segregated for non-regulated business | Yes | Exhibit A, Tab 6, Schedule 1 |
| 13 | Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application | Yes | Exhibit A, Tab 2, Schedule 2 |

| EXHIBIT 2 - Transmission System Plan | | | |
|---|---|---|---|
| *General* | *Note: NRLP has no planned Capital Expenditures* | | |
| Ch 2, p 13 | Refer to Chapter 5 of the Distribution Filing Requirements | Yes | |
| 13 | The strategic plan for the utility and investment strategy | Yes | Exhibit B, Tab 1, Schedule 2 |
| 13 | The longer term economic and planning assumptions | N/A | |
| 13 | The asset management plan | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3 |
| 13 | A description of how investments are prioritized and selected | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3 |
| 13 | A discussion of transmission investments identified in the regional planning process | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |
| 13 | Highlights of recent and proposed investments and their fit with the strategic plan | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 13 | A description of how the needs of customers and overall system planning policy objectives are being reflected | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.1.2 |
| 13 | Commitments stemming from the Long Term Energy Plan or the Conservation First policy, and consideration for the OEB's statutory objectives, including facilitating a smart grid and the connection of renewables | N/A | |
| *Asset Management Plan* | | | |
| Ch 2, p 14 | Asset management policy, strategy and objectives | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3 |
| 14 | Inventory and assessment of the condition of capital assets (by class and inclusion in BES), how this informs plan for capital expenditures and maintenance expenditures | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.2 |
| 14 | Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied | N/A | |
| *Regional Considerations* | | | |
| Ch 2, p 14 | Regional planning process demonstrating that regional considerations have been considered and addressed | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |
| 14 | Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |
| 14 | Identify investments spanning more than one region | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |

| | | | |
|---|---|---|---|
| *Coordinated Planning with Third Parties* | | | |
| Ch 2, p 15 | Description of the consultation including: the purpose of the consultation; whether the transmitter initiated the consultation or was an invitee; participants in the consultation; deliverables and impact on plan | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |
| *Capital Expenditures* | *Note: NR LP has no planned Capital Expenditures* | | |
| Ch 2, p 16 | Summary of capital expenditures over the past five historical years including the bridge year and five future years including the test year(s), showing treatment of contributed capital and additions and deductions from Construction Work in Progress | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 16 | Material Investments - For projects and programs:<br>- a description of the need, scope and purpose of the project or program<br>- customer attachments<br>- load and capital costs<br>- cost-benefit analysis<br>- identify where "leave to construct" required or project is necessary to comply with a licence condition | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 16 | Drivers of capital expenditure increases for the test year(s) | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 16 | The basis for the estimated budget for the project or program | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 16 | For the balance of capital expenditures, describe components of capital expenditure and provide a reconciliation of capital components to total capital budget | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 17 | Written explanation of capital expenditure variances | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 17 | The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 17 | Cost benchmarking studies or utility cost comparisons | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 17 | Continuous improvement or efficiency gains, how they will be achieved and benefit customers | Yes | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4 |
| 17 | A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income | Yes | Exhibit A, Tab 4, Schedule 1 |

| | | | |
|---|---|---|---|
| **EXHIBIT 3 - Rate Base** | | | |
| *Overview* | | | |
| Ch 2, p 17 | Opening and closing balances and the averages thereof gross assets and accumulated depreciation<br>Rate base shall include an allowance for working capital<br>Rate base must be supported by historical actuals, bridge year and test years | Yes | Exhibit C, Tab 1, Schedule 1 |
| 18 | Continuity statements (year end balance, including interest during construction and overheads).<br>Explanation for any restatement (e.g. due to change in accounting standards)<br>Year over year variance analysis; explanation where variance greater than materiality threshold<br>Hist. OEB-Approved vs Hist. Actual<br>Hist. Act. vs. preceding Hist. Act.<br>Hist. Act. vs. Bridge<br>Bridge vs. Test | Yes | Exhibit C, Tab 2, Schedules 2 to 4 |
| 18 | Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation | Yes | Exhibit C, Tab 1, Schedule 1<br>Exhibit C, Tab 2, Schedule 4 |
| 19 | Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format. | Yes | Exhibit C, Tab 1, Schedule 1<br>Exhibit C, Tab 2, Schedule 4 |
| *Gross Assets - PP&E and Accumulated Depreciation* | | | |
| Ch 2, p 19 | Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses | Yes | Exhibit C, Tab 2, Schedule 4 |
| 19 | Detailed breakdown by major plant account for each functionalized plant item; For the test year(s), each plant item must be accompanied by a description. | Yes | Exhibit C, Tab 2, Schedule 4 |
| 19 | Detailed breakdown of the in-service capital additions for the test year(s) | Yes | Exhibit C, Tab 1, Schedule 1 |
| 19 | Continuity statements must reconcile to calculated depreciation expenses and presented by asset account | Yes | Exhibit C, Tab 2, Schedule 4 |
| *Allowance for Working Capital* | *Not Applicable: NRLP requires no working capital* | N/A | Exhibit C, Tab 1, Schedule 1 |
| Ch 2, p 19 | Working Capital - Lead/Lag Study | N/A | |
| 19 | Lead/Lag Study - leads and lags measured in days, dollar-weighted | N/A | |
| 19 | For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources. | N/A | |
| *Customer Connection and Cost R* | *Not Applicable: NRLP has no customer driven Capital Expenditures* | N/A | |
| Ch 2, p 20 | The transmitter should show customer contribution amounts separately as an offset to rate base. | N/A | |
| 20 | Agreements reviewed on reaching a fifth anniversary and aggregated estimate of total expected true-up contributions and proceeds from bypass agreements | N/A | |
| 20 | Financial and regulatory accounting treatment of true-up proceeds. | N/A | |
| *Capitalization Policy* | *Not Applicable: NRLP has no overhead capitalized* | N/A | |
| Ch 2, p 20 | Capitalization policy, including changes since the last revenue requirement application | N/A | |
| 20 | Overhead costs on self-constructed assets | N/A | |
| 20 | Identification of burden rates and burden rates prior to changes, if any | N/A | |
| *Capital Module* | | | |
| Ch 2, p 21 | Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the Transmission System Plan; intended to come into service during the index period; Involve costs that the transmitter cannot manage through the revenue established through the index | N/A | |
| 21 | The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment. | N/A | |

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| **EXHIBIT 4 - Service Quality and Reliability Performance and Reporting** | | | |
| *Proposed Scorecard* | *Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision* | | |
| 21 | Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant measures | Yes | Exhibit D, Tab 1, Schedule 1 |
| *Reliability Performance* | *Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision* | | |
| 22 | Reliability performance measures: transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability | Yes | Exhibit D, Tab 1, Schedule 1 |
| 22 | Address performance standards for transmitters as set out in Chapter 4 of the TSC. | N/A | |
| 22 | Compare system performance with other systems both nationally and internationally | N/A | |
| *Compliance Matters* | | | |
| 22 | Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance | Yes | Exhibit B, Tab 1, Schedule 1 |
| **EXHIBIT 5 - Operating Revenue** | | | |
| *Load and Revenue Forecasts* | *Not Applicable: NRLP has no load forecast* | | |
| ~~23~~ | Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts | N/A | |
| ~~23~~ | Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses | N/A | |
| ~~23~~ | Detailed CDM forecast, with impact of CDM shown on the load forecast for each of the three rate pools. The applicant must also indicate how the forecast reflects IESO CDM forecasts and targets in the load forecast | N/A | |
| ~~23~~ | Impact of forecast embedded generation on the transmission system load accounted for | N/A | |
| *Accuracy of Load Forecast and V* | *Not Applicable: NRLP has no load forecast* | | |
| 23 | Demonstrate five year historical accuracy by providing schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for:<br>- Historical OEB-approved;<br>- Historical actual for the past 5 years;<br>- Historical actual for the past 5 years – weather normalized;<br>- Bridge year;<br>- Bridge year – weather normalized;<br>- Test year | N/A | |
| | *Not Applicable: NRLP has no load forecast* | | |
| 24 | Analyses and discussion for volumes, revenues, customer/connections count and total system load:<br>- Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences;<br>- Historical OEB-approved vs. historical actual;<br>- Historical OEB-approved vs. historical actual – weather normalized;<br>- Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years);<br>- Historical actual – weather normalized vs. bridge year – weather-normalized;<br>- Bridge year – weather-normalized vs. test year(s) | N/A | |
| 24 | All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format | N/A | |

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| *Other Revenue* | *Not Applicable: NRLP has no other revenue* | | |
| 24 | Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons | N/A | |
| 24 | How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges | N/A | |
| 24 | Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs | N/A | |
| 24 | Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue. | N/A | |
| **EXHIBIT 6 - Operating Cost** | | | |
| *Overview* | | | |
| Ch 2, p 25 | Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes, ~~benchmarking, description of the continuous improvement or efficiency gains~~ | Yes | Exhibit F, Tab 1, Schedule 1 |
| *Summary and Cost Driver Tables* | | | |
| Ch 2, p 26 | Summary of recoverable OM&A expenses | Yes | Exhibit F, Tab 2, Schedules 1 |
| 26 | Recoverable OM&A cost drivers | Yes | Exhibit F, Tab 2, Schedules 1 |
| 26 | Change in OM&A in test year attributable to a change in capitalized overhead | N/A | |
| 26 | OM&A variance analysis for test year with respect to bridge and historical years | Yes | Exhibit F, Tab 2, Schedules 1 |
| *Program Delivery Costs with Variance Analysis* | | | |
| **Ch 2, p 26** | O&M Costs for:<br>~~- employee compensation~~<br>~~- shared services~~<br>- corporate cost allocation<br>~~- purchase of non-affiliate services~~<br>- one-time costs<br>- OEB costs<br>- Charitable and political donations | Yes | Exhibit F, Tab 2, Schedules 1 |
| *Employee Compensation* | *Not Applicable: NRLP has no employees* | | |
| Ch 2, p 26 | Employee complement, compensation and benefits | N/A | |
| 26 - 27 | Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to headcount and compensation. Explanation for all years includes:<br>- year over year variances<br>- basis for performance pay, eligible employee groups, goals, measures and review process for pay-for-performance plans<br>- benchmarking studies | N/A | |
| 27 | Employee benefit programs including pensions | N/A | |
| 27 | Most recent actuarial reports | N/A | |

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| *Shared Services and Corporate Cost Allocation* | | | |
| Ch 2, p 27 | Identification of shared services | Yes | Exhibit F, Tab 2, Schedule 1 |
| 27 | Allocation methodology for corporate and shared services | Yes | Exhibit F, Tab 4, Schedule 1 |
| 28 | Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section | Yes | Exhibit F, Tab 2, Schedule 1 |
| 28 | Variance analysis - test year vs last OEB approved and most recent actual | Yes | Exhibit F, Tab 2, Schedule 1 |
| ~~28~~ | Identification of any Board of Director costs for affiliates included in LDC costs | N/A | |
| *Purchase of Non-Affiliate Services* | | | |
| ~~28~~ | Procurement Policy | N/A | |
| 28 | Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product and describe how vendor was selected | N/A | |
| *One-time Costs* | | | |
| 28 | One-time costs - historical, bridge, test year costs.<br>Explanation of cost recovery in test years.<br>Costs in the test years will not result in an over recovery in future years. | No | Exhibit F, Tab 1, Schedule 1 |
| *Regulatory Costs* | | | |
| 28 | Regulatory costs - breakdown of actual and forecast costs<br>Supporting information, legal fees, consultant fees, costs awards, etc. | Yes | Exhibit F, Tab 2, Schedule 1 |
| *Charitable and Political Donations* | | | |
| 29 | File the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s). | N/A | |
| 29 | Detailed information for all contributions that are claimed for recovery | N/A | |
| 29 | Charitable Donations - confirmation that political contributions not included | N/A | |
| *Depreciation, Amortization and Depletion* | | | |
| 29 | Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years.<br>Asset amount and rate of depreciation/amortization must tie back to the accumulated depreciation balances in the continuity schedule under rate base. | Yes | Exhibit F, Tab 5, Schedule 1 |
| 29 | Identification of any Asset Retirement Obligations and associated depreciation, accretion expense | Yes | Exhibit F, Tab 5, Schedule 1 |
| 29 | Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided | Yes | Exhibit F, Tab 5, Schedule 1 |
| 29 | Depreciation/amortization policy<br>Summary of changes to depreciation/amortization policy since last CoS | Yes | Exhibit F, Tab 5, Schedule 1, Attachment 1 and 3 |
| 29 | Explanation of any deviations from depreciating components of PP&E separately | N/A | |

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| *Taxes or PILs and Property Taxes* | | | |
| 30 | Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years | Yes | Exhibit F, Tab 6, Schedule 1 |
| 30 | Supporting schedules and calculations identifying reconciling items | Yes | Exhibit F, Tab 6, Schedule 2 Attachments 1 to 4 |
| 30 | Most recent federal and provincial tax returns | Yes | Exhibit F, Tab 7, Schedule 3 and Attachments 1 |
| 30 | Financial Statements included with tax returns if different from those filed with application | N/A | |
| 30 | Calculation of Tax Credits; redact where required (filing of unredacted versions is not required) | N/A | |
| 30 | Supporting schedules, calculations and explanations for other additions and deductions | Yes | Exhibit F, Tab 6, Schedule 1 |
| *Non-recoverable and Disallowed Expenses* | | | |
| 30 | Exclude from regulatory tax calculation any non-recoverable or disallowed expenses | N/A | |
| *Integrity Checks* | | | |
| 31 | Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | CCA is maximized even if there are tax loss carry-forwards | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | A statement is included in the application as to when the losses, if any, will be fully utilized | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation | Yes | Exhibit F, Tab 6, Schedule 1 |
| 31 | The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding. | Yes | Exhibit F, Tab 6, Schedule 1 |
| *Z-Factor Claims* | | | |
| **31** | Evidence that z-factor costs incurred meet eligibility criteria, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement | Yes | Exhibit F, Tab 8, Schedule 1 |

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| **EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE** | | | |
| *Capital Structure* | | | |
| 33 | OEB's cost of capital parameters used | Yes | Exhibit G, Tab 1, Schedule 1 |
| 33 | Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years | Yes | Exhibit G, Tab 1, Schedule 1 |
| 33 | Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules | Yes | Exhibit G, Tab 1, Schedule 3 |
| 33 | Explanation for any changes in capital structure | Yes | Exhibit G, Tab 1, Schedule 1 |
| *Cost of Capital (Return on Equity and Cost of Debt)* | | | |
| 34 | Calculation of cost for each capital component | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Profit or loss on redemption of debt | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Copies of promissory notes or other debt arrangements with affiliates | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Explanation of debt rate for each existing debt instrument | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | Forecast of new debt in bridge and test year - details including estimate of rate | Yes | Exhibit G, Tab 1, Schedule 1 |
| 34 | If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions | Yes | Exhibit G, Tab 1, Schedule 1 |
| *Not-for-Profit Corporations* | | | |
| 34 | Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves | N/A | |
| **EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS** | | | |
| **34** | List of all outstanding DVA and sub-accounts; provide description of DVAs | Yes | Exhibit H, Tab 1, Schedule 1 |
| **34** | Completed DVA continuity schedule for period following last disposition to present - live Excel format | Yes | Exhibit H, Tab 1, Schedule 2 |
| **34** | Confirm use of interest rates established by the OEB by month or by quarter for each year | Yes | Exhibit H, Tab 1, Schedule 1 |
| **35** | Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS | Yes | Exhibit H, Tab 1, Schedule 1 |
| **35** | A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule | Yes | Exhibit I1, Tab 1, Schedule 3 |
| **35** | Statement as to any new accounts, and justification. | Yes | Exhibit H, Tab 1, Schedule 1 |
| **35** | Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents | Yes | Exhibit H, Tab 1, Schedule 1 |
| *Disposition of Deferral and Variance Accounts* | | | |
| 36 | Identify accounts for which disposition is sought | No | Exhibit H, Tab 1, Schedule 1 |
| 36 | Identify accounts for which disposition is not sought and the reasons | No | Exhibit H, Tab 1, Schedule 1 |
| 36 | Propose the method to be used for recovery or refund of balances that are proposed for disposition | No | Exhibit H, Tab 1, Schedule 1 |
| 36 | Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements | No | Exhibit A, Tab 6, Schedule 3, Exhibit H, Tab 1, Schedule 1 |
| 36 | Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account | N/A | |
| 36 | Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference | N/A | |
| 36 | Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period | N/A | |

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| **EXHIBIT 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants** | | | |
| | *Scope: NRLP is allocated to the Network Pool* | | |
| 36 | Identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection | Yes | Exhibit I, Tab 1, Schedule 1 |
| 36 | Steps taken to functionalize the assets in the functional categories | Yes | Exhibit I, Tab 1, Schedule 1 |
| 36 | Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets | N/A | |
| 36 | Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools | N/A | |
| **EXHIBIT 10 - Rate Design for Uniform Transmission Rates** | | | |
| *Bill Impact Information* | | | |
| 37 | Provide bill impact of the application including the dollar and percentage impact on the average customer's total bill and the percentage impact on transmission rates | Yes | Exhibit I, Tab 2, Schedule 1 |
| 37 | Bill impacts for typical customers and consumption levels. | Yes | Exhibit I, Tab 2, Schedule 1 |
| *Setting the Uniform Transmission Rates* | | | |
| 37 | Overview of how the UTR are established in Ontario and how these rates are determined | Yes | Exhibit I, Tab 2, Schedule 1 |
| 37 | The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool | Yes | Exhibit I, Tab 2, Schedule 1 |
| 37 | Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates | N/A | |
| 37 | A table explaining and documenting the determination of the UTR including:<br>- previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool;<br>- OEB file number of each decision approving each revenue requirement and charge determinant;<br>- proposed revenue requirements and charge determinants as proposed in the application;<br>- the calculation of the UTR for each pool;<br>- the transmission revenue allocator for each of the Ontario transmitters in the pool;<br>- an explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates | Yes | Exhibit I, Tab 2, Schedule 1<br>Exhibit I, Tab 3, Schedule 1<br>Exhibit I, Tab 3, Schedule 1, Attachment 1<br>Exhibit I, Tab 3, Schedule 1, Attachment 2 |

# Distribution System Plan Checklist (as applied to the TSP)

**NRLP**

**Filing Requirement Page # Reference**

**Date: July 12, 2018**

| Filing Requirement Page # Reference | | Yes/No/N/A | Evidence Reference, Notes |
|---|---|---|---|
| **DISTRIBUTION SYSTEM PLAN REQUIREMENTS** | | | |
| **Ch 5 p7-8** | Where applicable, explanation for section headings other than Chapter 5 head | **Yes** | |
| **Ch 5 p8-9** | (Ch. 5.2.1) Distribution System Plan Overview - key elements, sources of cost savings, period covered, vintage of information on investment drivers, changes to asset management process since last DSP filing, dependencies | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.1 |
| **Ch 5 p9-10** | (Ch. 5.2.2) Coordinated Planning with 3rd parties - description of consultations<br>- deliverables of the Regional Planning Process, or status of deliverables<br>- IESO letter in relation to REG investments (Ch 5 p10) and Dx response letter | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2 |
| **Ch 5 p10-12** | (Ch. 5.2.3) Performance Measurement - identify and define methods and measures used to monitor DSP performance<br>- summary of performance and trends over historical period. Must include SAIFI and SAIDI for all interruptions and all interruptions excluding loss of supply<br>- explain how information has affected DSP | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.3 |
| **Ch5 p13** | (Ch. 5.3.1.a) Asset Management Process Overview - description of AM objectives/corporate goals and how objectives for prioritizing investments are ranked | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.1 |
| **Ch5 p13** | (Ch. 5.3.1.b) Inputs/Outputs of the AM process and information flow for investments; flowchart recommended | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.1 |
| **Ch 5 p14** | (Ch. 5.3.2) Overview of Assets Managed - description of service area (including evolution of features in forecast period affecting DSP),<br>- description of system configuration<br>- service profile and condition by asset type (tables and/or figures) - date data compiled<br>- assessment of degree the capacity of system assets is utilized | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.2 |
| **Ch 5 p14-15** | (Ch. 5.3.3) Asset Lifecycle Optimization - description of asset lifecycle optimization policies and practices, including asset replacement and refurbishment, maintenance planning criteria and assumptions<br>- description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.3 |
| **Ch 5 p17-18** | (Ch. 5.4.1) Capital Expenditure Planning Process Overview - description of capex planning objectives/criteria/<br>assumptions, relationship with AM objectives, policy on consideration of non-distribution alternatives, processes used to identify projects in each investment category, customer feedback and impact on plan, method and criteria used to prioritise REG investments | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.1 |
| **Ch 5 p19-20** | (Ch. 5.4.2) Capital Expenditure Summary is to provide a snapshot of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or trigger) driver of the investment. | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.2 |
| **Ch 5 p20** | (Ch. 5.4.3) Justifying capital expenditures - Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures. | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3 |
| **Ch 5 p20-21** | (Ch. 5.4.3.1) Capital Expenditure Summary by Investment Category - The OEB's assessment of DSPs includes the costs of material projects/programs included in the DSP, as well as how the overall DSP budget is allocated to each of the<br>four investment categories. | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3 |
| **Ch5 p21-28** | (Ch. 5.4.3.2) Material Investments - For each project that meets materiality threshold set in Ch 2 p10<br>- general information - total capital, customer attachments, dates, risks, variances, REG investments<br>- evaluation criteria - may include: efficiency, customer value, reliability, etc.<br>- category specific requirements for each project - system access, system renewal, system service, general plant (as applicable) | **Yes** | Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3 |

# SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

NRLP is a new transmitter and this is the first revenue requirement application for NRLP. Consequently, there are no Ontario Energy Board ("OEB") directives or undertakings from any previous NRLP cost of service proceedings in respect of this Application.

As part of this application, NRLP is filing, on behalf of HONI, an update on the final Niagara Reinforcement project costs. This request arises from the OEB decision in the asset transfer application that determined that the value of the Niagara Reinforcement assets would be determined in a future rate proceeding.

# SUMMARY OF APPLICATION

This Exhibit describes the scope and key aspects of Niagara Reinforcement Limited Partnership's ("NRLP") application (the "Application") in respect of its proposed transmission rates for 2020 to 2024 (the "Test Period"). Given that NRLP operates a single transmission asset, with minimal operating costs and no forecast capital expenditures, NRLP proposes that this Application may be most effectively and efficiently dealt with by way of Settlement.

## 1. NIAGARA REINFORCEMENT LIMITED PARTNERSHIP

NRLP is a Limited Partnership between Hydro One Indigenous Partnerships GP Inc. ("HOIP"), Hydro One NRLP Inc., both of which are affiliates of Hydro One Inc. ("HOI"), Six Nations of the Grand River Development Corporation ("SNGRDC"), and the Mississaugas of the Credit First Nation ("MCFN"), which has fundamentally allowed for the development, construction and in-service operation of HONI's Niagara Reinforcement Project ("NRP" or "the Project"). Completion of this project provides greater maintenance flexibility and more power transmission capacity to the load centres of the Greater Toronto and Hamilton areas.

NRLP owns assets that are located in southern Ontario in the Niagara region and are comprised of a new 76 km double circuit 230 kV transmission line connecting Allanburg Transformer Station and Middleport Transformer Station.

## 2. SCOPE OF APPLICATION

In this Application for transmission rates for 2020 to 2024, NRLP is requesting the Ontario Energy Board's ("OEB" or "Board") approval for, among other things:[1]

i. Revenue requirement for 2020 (the "Test year"), determined by using a cost of service, forward test-year approach;
ii. Uniform Transmission Rates ("UTR") for the Network pool for the Test year;
iii. The proposed Revenue Cap Index mechanism to establish revenue requirement and UTRs for 2021 to 2024;
iv. The establishment and continuation of NRLP's regulatory accounts;
v. An accounting order establishing an Earnings Sharing Mechanism Deferral Account;
vi. An effective date of January 1, 2020, for the Test year rates;
vii. Updating the cost of long-term debt in 2021 to reflect the actual long-term debt rate;
viii. An order allowing NRLP to utilize US GAAP for financial reporting purposes; and,
ix. Other items that may be requested during the course of this application.

NRLP's Revenue Cap IR Application, as proposed, will help the partnership ensure that NRLP's assets are managed efficiently and effectively.

The Application will result in a 2020 revenue requirement of $9.4 million, with an annual increase of 1.4% in the revenue requirements from 2021 to 2024, as discussed in Section 5. The 2020 revenue requirement is adjusted to include $6.4 million for the disposition of the regulatory account balance, resulting in $15.8M as the rates revenue requirement.[2]

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[1] As described in Exhibit A, Tab 2, Schedule 1.
[2] As described in Exhibit E, Tab 1, Schedule 1.

The 2020 network UTR increases by $0.06 to $3.89 per kW-Month, a 1.6% increase relative to 2019[3]. This increase is partly attributable to the adjustment for the disposition of regulatory account balances. NRLP does not propose any disposition of regulatory account balance from 2021 to 2024. As a result, the 2021 network UTR decreases by $0.03 to $3.86 per kW-Month, which is a 0.8% decrease relative to 2020. The Line Connection and Transformation Connection UTRs are unaffected.

The 2020 rates revenue requirement will result in a 0.9% increase on average transmission rates, and a total bill impact of 0.05% (6 cents per month) for a typical Residential (R1) customer consuming 750 kW per month and, similarly, a total bill impact of 0.03% (13 cents per month) for a typical energy-billed General Service (GS < 50 kW) customer consuming 2,000 kWh per month. The 2021 rates revenue requirement will result in a 0.4% decrease on average transmission rates, and a total bill impact of -0.02% (2 cents less per month) for a typical Residential (R1) customer consuming 750 kW per month and, similarly, a total bill impact of -0.01% (5 cents less per month) for a typical energy-billed General Service (GS < 50 kW) customer consuming 2,000 kWh per month. This application is expected to have no impact on customer bills from 2022 to 2024. Further details can be found in Exhibit I, Tab 2, Schedule 1.

## 3. REVENUE CAP INDEX

The Application is based on a Revenue Cap Index mechanism in which the revenue requirement for the Test year (2020) is determined by using a cost of service, forward test-year approach.

[3] Per EB-2019-0164 Decision and Rate Order dated July 25, 2019

To establish the annual revenue requirements for 2021 to 2024, a Revenue Cap Index ("RCI") is proposed in which the revenue requirement for the Test year (t+1) is equal to the revenue requirement in year t, inflated by the RCI.

The RCI is expressed as:

$$RCI = I - X$$

Where:

- “I” is the Inflation Factor, based on Hydro One Networks Inc.’s custom weighted two-factor input price index; and
- “X” is the Productivity Factor, which includes a Stretch Factor.

NRLP proposes to adopt the RCI Inflation Factor (“I”) parameter proposed by Hydro One Networks Inc. in its current transmission rates proceeding (EB-2019-0082), to be consistent with the transmission sector. The proposed Inflation Factor is an external measurement of the transmission industry labour/non-labour weights and would be the same regardless of the transmission company to which it is being applied.[4]

The proposed Inflation Factor (“I”) is based on the weighted sum of:

- 86% of the annual percentage change in Canada’s GDP-IPI (FDD), as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The proposed weighting is derived from the analysis conducted by Power Systems Engineering Inc. (“PSE”) in its study found in EB-2019-0082 at Exhibit A, Tab 4, Schedule 1. Based on the most recent OEB-reported results, NRLP has used the Inflation Factor of 1.4% derived above, on a pro forma basis in its RCI calculation for each of the 2021 to 2024 Test years, for the purpose of this Application.

NRLP proposes a 0% Productivity Factor (“X”) to be applied annually over the 2021 to 2024 period. NRLP operates under unique circumstances unlike other transmission companies in Ontario when considering its corporate structure, asset holdings, and

[4] EB-2018-0218 Hydro One Sault Ste. Marie, Interrogatory I-1-58.

operating and management arrangements. NRLP's proposal reflects these circumstances and is appropriate for the following reasons:

- NRLP's assets are new and require low OM&A in comparison to other transmitters with no forecast capital expenditures during the rate period;
- NRLP's only controllable costs are OM&A. These costs are a small fraction of the total costs and are significantly less than the non-controllable portion of its costs (Cost of Capital, Depreciation, Income Tax). NRLP is able to implement few if any initiatives or otherwise take actions that would meaningfully affect these costs, which represent nearly all of NRLP's expenditures. Cost efficiencies that NRLP might engender in response to the application of a Productivity and Stretch Factor similar to other transmitters would be effectively impossible to realize;[5]
- NRLP's management and work programs are provided by a service level agreement with HONI, an established, robust service provider in the Ontario market with assets located in the same region as NRLP. This agreement results in minimal overhead while providing qualified and flexible resources when needed, allowing NRLP to remain cost efficient;
- NRLP's service level agreement integrates HONI's productivity improvements into NRLP's maintenance operations; and
- The NRLP partnership allows for a tax structure that provides rate payers with lower income tax costs compared to many of Ontario's other transmitters over the life of the asset.

To align NRLP's business interests with those of ratepayers and provide an additional element of protection to them, NRLP is also proposing the following features:

[5] In addition, preparing a benchmarking report would yield results of limited utility. The report would require a high degree of customization, including for example the removal of capital costs, facilities, stations and other lines (115kV and 500kV) costs, among other things.

- An earnings sharing mechanism ("ESM") that will protect customers by sharing 50% of earnings that exceed the regulatory ROE by more than 100 basis points in any year of the Revenue Cap Index term; and
- using Z-factor and off-ramp mechanisms that apply OEB-approved criteria.

## 4. NRLP'S STRATEGIC PLAN

NRLP's strategic plan on which this Application is based was informed by its values and strategic objectives described in the section below.

NRLP is sensitive to and has considered the needs of provincial ratepayers that have expressed a desire for low rates and high reliability (based on research undertaken by HONI). NRLP's plan supports these general ratepayer objectives by proposing no planned capital spending and a minimal OM&A budget required to maintain NRLP's transmission reliability.

NRLP's Strategic Plan may be found at Exhibit B, Tab 1, Schedule 2.

### 4.1 NRLP'S VALUES AND STRATEGIC OBJECTIVES

NRLP, as part of the Hydro One family of companies, is driven primarily by the values of health and safety, and stewardship. NRLP's strategy and business values must operate with rates that can balance the financing of investment in infrastructure while maintaining affordable and reliable service.

NRLP will be 45% owned by a partnership of First Nations[6] over whose traditional territory the transmission line crosses. Respect for Indigenous peoples and their traditions is another key value of the partnership.

NRLP's business is underpinned and driven by its strategic objectives. These objectives consist of the following:

- Oversee a service level agreement with Hydro One Networks Inc. that supports creating an injury-free workplace and maintaining public safety;
- Foster relationships with the owners of the partnership and the Indigenous communities;
- Maintain a reliable, cost-effective transmission system;
- Protect and sustain the environment for future generations;
- Maintain a commercial culture that increases value for its owners; and
- Achieve productivity improvements and cost effectiveness.

The five-year vision associated with NRLP's strategic objectives is shown in Table 1. In managing its transmission assets, NRLP is committed to meeting the OEB's Renewed Regulatory Framework ("RRF") outcomes as demonstrated by the alignment of NRLP's strategic objectives to the RRF outcomes.

**Table 1 - NRLP Strategic Objectives**

| RRF Outcomes | Strategic Objectives | Five-Year Vision |
|---|---|---|
| Customer Focus | Foster Indigenous Relationships | Continue to maintain effective and beneficial relationships. |
| Operational Effectiveness | Injury-Free | Ensure NRLP's operations and management services agreement is executed in accordance with good utility practice for employee and public safety. |

[6] MCFN have chosen to defer their full investment in the partnership until the earlier of the date a rate order is issued by the OEB or 6 months from the purchase date. Until the initial rate order is issued, they will will own 0.1% of the partnership and Hydro One will own 74.9%. Upon receipt of the rate order, MCFN will purchase the remainder of their final interest of 20% and Hydro One will then own 55%.

| RRF Outcomes | Strategic Objectives | Five-Year Vision |
|---|---|---|
| | Reliable Transmission | Continue to maintain a reliable transmission system. |
| | Cost Control | Strive to minimize costs and pass on savings to the customers of the province. |
| Public Policy Responsiveness | Protecting the Environment | Sustainably manage NRLP's environmental footprint. |
| Financial Performance | Owner's Value | Achieve the Regulated Return On Equity allowed by the Ontario Energy Board. |

## 5. KEY ELEMENTS OF THE APPLICATION

### 5.1 REVENUE REQUIREMENT

NRLP's 2020 revenue requirement is shown in Table 2. The revenue requirement in subsequent years of the Test period will be determined using the RCI, which is described in Exhibit A, Tab 4, Schedule 1.

**Table 2 - Revenue Requirement ($ Millions)**

| Components | 2019[1] | 2020 | Reference |
|---|---|---|---|
| OM&A | 0.28 | 0.85 | Exhibit F, Tab 1, Schedule 1 |
| Depreciation | 0.79 | 1.59 | Exhibit F, Tab 5, Schedule 1 |
| Income Taxes | 0.03 | 0.06 | Exhibit F, Tab 6, Schedule 1 |
| Return on Capital | 3.57 | 6.89 | Exhibit G, Tab 1, Schedule 1 |
| Start-Up and Development Costs Recovery | 1.71 | 0.00 | Exhibit F, Tab 1, Schedule 1 |
| **Base Revenue Requirement** | **6.38** | **9.39** | |
| Deduct External Revenues and Other | 0.00 | 0.00 | |
| **Rates Revenue Requirement** | **6.38** | **9.39** | |

*Exhibit Reference: E-1-1, Table 1.*

The proposed Revenue Cap IR Application would result in the base revenue requirement over the Test period as shown in Table 3.

**Table 3 - Base Revenue Requirement by Year**

| Year | Formula | Base Revenue Requirement |
|---|---|---|
| 2020 | Cost of Service | **5.1.1** $9.39 million |
| 2021 | 2020 Base Revenue Requirement* x 1.014** | **5.1.2** $9.52 million |
| 2022 | 2021 Base Revenue Requirement* x 1.014 | **5.1.3** $9.65 million |
| 2023 | 2022 Base Revenue Requirement* x 1.014 | **5.1.4** $9.79 million |
| 2024 | 2023 Base Revenue Requirement* x 1.014 | **5.1.5** $9.93 million |

** Calculations assume RCI in Exhibit A, Tab 4, Schedule 1 Table 2*
*** Exhibit E, Tab 1, Schedule 1, Table 1: To be updated to reflect the actual market rate of the cost of long-term debt after debt refinancing has been completed.*

## 5.2 BUDGETING ASSUMPTIONS

NRLP has included no future capital expenditures. Therefore, assumptions regarding inflation and exchange rates have not been provided.

## 5.3 LOAD FORECAST

NRLP has included no load forecast, as it has no metering points or delivery points. All power transported using NRLP's assets are delivered to the final customer by another transmitter and thus is included in another transmitter's load forecast. The revenue requirement is allocated to the provincial Network rate pool, as all assets serve the Network with no Transformation or individual customer services. Once the revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each pool to the total revenue for each pool.

## 5.4 TRANSMISSION SYSTEM PLAN

This section summarizes the major drivers and elements of NRLP's five-year TSP (Exhibit B, Tab 1, Schedule 3, Attachment 1). NRLP has aligned its TSP in accordance with Chapter 2 of the Ontario Energy Board's ("OEB") *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016, with further guidance from Chapter 3 and 5 of the OEB's Filing Requirements (*Incentive Regulation* and *Consolidated Distribution System Plan Filing Requirements*), revised on July 12, 2018 (together, the “Filing Requirements”).

### 5.4.1 ASSET MANAGEMENT PROCESS

NRLP continues to retain Hydro One Networks Inc. under a service level agreement to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support services.

NRLP relies upon Hydro One Networks Inc.’s asset management process. Hydro One Networks Inc. has continued to implement several refinements in its asset strategies and investment assessment to improve upon its asset management process, as documented in Exhibit B, Tab 1, Schedule 1 of Proceeding EB-2019-0082. NRLP expects that these changes will potentially benefit NRLP in a future period.

### 5.4.2 INVESTMENT PLANNING PROCESS

NRLP’s operational needs are assessed by Hydro One Networks Inc. on an annual basis and are incorporated into Hydro One Networks Inc.’s investment planning process to establish a plan that addresses those operational needs while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets.

### 5.4.3 CAPITAL EXPENDITURES

NRLP’s transmission assets are limited to the components of a single 230kV double circuit transmission line. Given the relatively new vintage of this line, no planned capital spending is required to meet the Applicant’s business objectives over the 2020 to 2024 planning period. The absence of capital spending will result in no in-service additions to grow its rate base during the planning period.

NRLP's assets were placed into service on August 30, 2019. Therefore, minimal degradation has occurred, and these assets are considered to have a low condition risk.

## 5.5 RATE BASE

The requested rate base over the Test period is provided in Table 4 below. Details are provided in Exhibit C, Tab 1, Schedule 1.

**Table 4 - Transmission Rate Base ($ Millions)**

| Description | Bridge OEB Approved** 2019 | Test* 2020 |
|---|---|---|
| Mid-Year Gross Plant | 59.72 | 119.43 |
| Average Mid-Year Accumulated Depreciation | (0.40) | (1.59) |
| **Mid-Year Net Plant** | 59.32 | 117.84 |
| Cash Working Capital | 0.0 | 0.0 |
| Materials and Supply Inventory | 0.0 | 0.0 |
| **Transmission Rate Base** | 59.32 | 117.84 |

** Exhibit Reference: C-1-1, Table 1*

## 5.6 PERFORMANCE AND REPORTING

NRLP is proposing to utilize a set of measures that best demonstrate its performance. The proposed performance measures and their associated RRF performance outcomes are shown in Table 5.

**Table 5 - NRLP's Performance Measures**

| RRF Outcomes | Performance Measure |
|---|---|
| Operational Excellence | Average System Availability (%) |
| Public Policy Responsiveness | NERC Vegetation Compliance |
| Operational Excellence | OM&A Cost ($K) per circuit kilometre |
| Financial Performance | Return on Equity (%) |

Given the nature of NRLP's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. NRLP's assets consist solely of a 230kV double circuit transmission line and do not include any terminal breakers or other operable assets, as the demarcation point of each of the circuits is at a tower outside of the station as noted in Exhibit B, Tab 1, Schedule 1. NRLP does not have any customer delivery points (or meter assets), which are the basis of common reliability performance measures such as SAIDI and SAIFI. In addition to these operating characteristics, the life-cycle of NRLP's assets detracts from meaningful comparisons. Therefore, NRLP's performance measures do not readily provide meaningful comparisons to other transmitters. On this basis, NRLP proposes that System Average Interruption Frequency and System Average Interruption Duration no longer be monitored. Instead, NRLP proposes to measure System Availability as a metric to demonstrate the reliability performance of the assets. Furthermore, NRLP has no customers; therefore, no Customer Focus measures have been proposed.

Further details on the methods and measures as well as the historical performance and forecast targets are documented in Exhibit D, Tab 1, Schedule 1.

### 5.7 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A)

NRLP will be managed by its general partner, Hydro One Indigenous Partnerships GP Inc. ("HOIP"), which will retain Hydro One Networks Inc. ("HONI"), under a Service Level Agreement, to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support services as outlined in Exhibit F, Tab 3, Schedule 1.

OM&A expenses are derived based upon the various work programs and functions performed by or on behalf of the Partnership. The estimated total OM&A expense is

$0.8 million in 2020. Further details on the OM&A costs are provided in Exhibit F, Tab 2, Schedule 1 and presented in Table 6.

**Table 6 - Summary of OM&A ($ Millions)***

| **Description** | **Test** |
|---|---|
| | **2020** |
| | **Forecast** |
| Service Level Agreement Costs | 0.53 |
| Incremental Expenses | 0.32 |
| **Total OM&A** | 0.85 |

## 5.8 COST OF CAPITAL

Table 7 below summarizes the return on capital for the 2020 Test year.

**Table 7 - 2020 Cost of Capital**

| **2020** | | | | |
|---|---|---|---|---|
| **Amount of Deemed Return** | **($M)** | **%** | **Cost Rate (%)** | **Return ($M)** |
| Long-term debt | 65.99 | 56% | 3.82% | 2.52 |
| Short-term debt | 4.71 | 4% | 2.82% | 0.13 |
| Common equity | 47.14 | 60% | 8.98% | 4.23 |
| **Total** | **117.84** | **100%** | **5.84%** | **6.89** |

*Exhibit Reference: G-1-1*

NRLP's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base. The 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt.[7]

[7] Consistent with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

NRLP will update the revenue requirement for the 2020 Test Year when the OEB releases its 2020 cost of capital parameters to reflect: (a) the OEB-approved 2020 return on equity and short-term debt rates; and (b) a long-term debt rate based on NRLP's weighted average of its existing debt rate and the rate on NRLP's forecast debt refinancing in 2020, using the September 2019 Consensus Forecast. NRLP proposes that the 2020 cost of capital parameters established at that time be used to determine the final revenue requirements for the 2020 Test year.

NRLP anticipates that the OEB will issue its Decision and Order in this proceeding prior to NRLP issuing new debt to refinance its maturing long-term debt in 2020. The future financing rate on 100% of NRLP's long-term debt is unknown and could have a material impact on NRLP's financial performance if the actual cost is not reflected in rates. NRLP proposes a one-time update to the cost of long-term debt at the first annual update for rates in 2021, to reflect the actual market rate achieved on the long-term debt it will issue. Based on the current forecast rates, the cost of debt for 2021 is expected to be 3.63%.

Further details regarding the cost of capital can be found in Exhibit G, Tab 1, Schedule 1.

## 5.9 COST ALLOCATION AND RATE DESIGN

All assets associated with NRLP are classified as Network assets. Accordingly, all of the rates revenue requirement associated with NRLP's transmission assets will be allocated to the Network pool. Further details regarding the cost allocation and rate design can be found in Exhibit I, Tab 1, Schedule 1.

## 5.10 DEFERRAL AND VARIANCE ACCOUNTS

On September 26, 2019, the Board issued approval for NRLP to create a deferral account to capture the costs associated with the period from September 1 to December 31, 2019.

Table 10 below displays the amounts that are projected to be in the account as of December 31.

**Table 8 – Forecast Balance in NRLPDA on December 31 ($ Million)**

| Components | 2019 |
|---|---|
| OM&A | 0.28 |
| Depreciation | 0.79 |
| Income Taxes | 0.03 |
| Return on Capital | 3.57 |
| Start-Up and Development Costs Recovery | 1.71 |
| **Total** | **6.38** |

NRLP is requesting approval to continue all existing accounts and to establish an Earnings Sharing Mechanism (ESM) Deferral Account, as detailed in Exhibit H, Tab 1, Schedule 1. The ESM Deferral Account would record and share with customers 50% of any over-earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points realized during any year of the Test period.

## 5.11 BILL IMPACTS

Exhibit I, Tab 2, Schedule 1 provides the bill impacts that would result from approval of the Application, along with illustrative bill impacts for 2021 - 2024. Table 9 shows the average 2020 bill impacts of the proposed changes in transmission rates revenue requirement and load forecast.

**Table 9 - Average Bill Impacts on Transmission and Distribution-connected Customers**

| | **2020 (Note)** |
|---|---|
| Rates Revenue Requirement ($Millions) | 15.8 |
| % Increase in Rates Revenue Requirement over prior year | N/A* |
| % Impact of load forecast change | 0.0% |
| NRLP Rates Revenue Requirement as a % of all transmitters | **5.11.1** 0.9% |
| **Net Impact on Average Transmission Rates** | 0.9% |
| Transmission as a % of Tx-connected customer's Total Bill | 8.2% |
| **Estimated Average Bill impact** | 0.08% |
| Transmission as a % of Dx-connected customer's Total Bill | 6.8% |
| **Estimated Average Bill impact** | 0.06% |

*Note: 2020 Rates Revenue Requirement per Exhibit E, Tab 1, Schedule 1, and 2021-2024 Rates Revenue Requirement per Exhibit A, Tab 4, Schedule 1.*

**N/A as 2019 rates revenue requirement is zero.*

The total bill impact for a typical Hydro One Networks Inc. medium density residential (R1) customer consuming 750 kWh, and for a typical Hydro One General Service (GSe) customer consuming 2,000 kWh/month is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 10.

**Table 10 - Typical Medium Density (R1) Residential Customer Bill Impacts**

| | **Typical Medium Density (HONI R1) Residential Customer 750 kWh** | **Typical General Service Energy less than 50 kW (HONI GSe < 50kW) Customer 2,000 kWh** |
|---|---|---|
| Total Bill as of May 1, 2018[1] | $124.30 | $389.14 |
| RTSR included in R1 Customer's Bill (based on 2019 Interim UTR) | $11.94 | $25.21 |
| *Estimated 2020 Monthly RTSR[2]* | $12.00 | $25.33 |
| **2020 increase in Monthly Bill** | **$0.06** | **$0.13** |
| *2020 increase as a % of total bill* | *0.05%* | *0.03%* |

*[1]Total bill including HST, based on time-of-use commodity prices and distribution rates effective May 1, 2018 (implemented July 1, 2019) approved per Distribution Rate Order EB-2017-0049 (includes impacts of all applicable components of the Fair Hydro Plan).*
*[2]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 9.*

## 6. CONCLUSION

NRLP's Application balances the needs of its system and assets and allows it to operate and maintain these assets in accordance with reliability standards and to satisfy regulatory, environmental, and legal requirements.

NRLP operates under unique circumstances, unlike those of most other transmission companies in Ontario, when considering its corporate structure, asset holdings, and operating and management arrangements. In consideration of these unique circumstances, NRLP has made every effort to align its Application with the OEB's expectations under the RRFE.

Over the five-year term, this Application, as proposed, will mitigate the company's challenges, maintain the Partnership's financial performance and ensure that NRLP's assets are managed effectively to benefit electricity customers across Ontario.

# REVENUE CAP APPLICATION SUMMARY

## 1. APPLICATION STRUCTURE

NRLP's application is based on a Revenue Cap Incentive Rate-Setting ("IR") approach for a five-year period. The methodology utilized is a Revenue Cap IR in which the revenue requirement for the Test year t+1 is equal to the revenue requirement in the Test year t, inflated by the Revenue Cap Index ("RCI") set out below.

NRLP's revenue requirement in the first year (2020) of the five-year period is determined by using a cost of service, forward test-year approach, consistent with the OEB's Renewed Regulatory Framework for Electricity ("RRFE") as most recently set out in the Handbook for Utility Rate Applications (the "Handbook"), released by the OEB in October 2016. The revenue requirement in the following years, 2021 to 2024, is determined by using an RCI that is calculated for each year.

The RCI includes an industry-specific inflation factor and a productivity factor. Consistent with the RRFE, the productivity factor is explicitly included in the rate adjustment mechanism and provides an incentive to achieve capital and OM&A productivity improvements.

The RCI is expressed as:

$$RCI = I - X$$

Where:

- "I" is the Inflation Factor, based on Hydro One Networks Inc.'s custom weighted two-factor input price index; and

  "X" is the Productivity Factor, which includes a Stretch Factor.

## 1.1 INFLATION FACTOR

NRLP proposes to adopt the RCI Inflation Factor ("I") parameter proposed by Hydro One Networks Inc. in its current transmission rates proceeding (EB-2019-0082). The proposed Inflation Factor is designed to be an external measurement of the broader transmission industry labour/non-labour weights and would be the same regardless of the transmission company filing it.[1]

The proposed Inflation Factor ("I") is based on the weighted sum of:

- 86% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The proposed weighting of 14% labour and 86% non-labour is derived from the analysis conducted by Power Systems Engineering Inc. ("PSE") in its study found in EB-2019-0082 at Exhibit A, Tab 4, Schedule 1, Attachment 1.

The latest annual percent change for the GDP-IPI and the Average Weekly Earnings for Workers in Ontario was released by the OEB on November 23, 2018, for use in applications for rates effective in 2019. The derivation of NRLP's proposed Inflation Factor is shown in Table 1 below.

[1] EB-2018-0218 Hydro One Sault Ste. Marie, Interrogatory I-1-58.

**Table 1 - Derivation of Inflation Factor**

| | Non-Labour GDP-IPI (FDD) - National | | | | | | | Labour AWE - All Employees - Ontario | | | Resultant Value - Annual Growth for the 2-factor IPI |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Q1 | Q2 | Q3 | Q4 | Annual | Annual % Change (A) | Weight (B) | Annual | Annual % Change ( C ) | Weight (D) | Annual % Change ([A*B]+[C*D]) |
| 2016 | 116.5 | 116.4 | 116.9 | 117.5 | 116.825 | | | 973.75 | | | |
| 2017 | 118.0 | 118.5 | 118.2 | 119.0 | 118.425 | 1.4% | 86% | 992.55 | 1.9% | 14% | 1.4% |

NRLP has used the Inflation Factor of 1.4% derived above, in its RCI calculation for each of the 2021 to 2024 test years, for the purpose of this Application.

The Inflation Factor will be updated annually using the OEB's posted Inflation Factor for distributors in each of 2020, 2021, 2022 and 2023, effective 2021, 2022, 2023 and 2024, respectively.

## 1.2 PRODUCTIVITY FACTOR

NRLP has considered the OEB's expectation for the development of a Revenue Cap "index, as well as productivity and stretch commitments."[2] However, given NRLP's unique circumstances, the Company proposes a 0% Productivity Factor ("X") and that the factor is continued over the 2021 to 2024 period.

NRLP operates under unique circumstances unlike some transmission companies in Ontario, when considering its corporate structure, asset holdings, and operating and management arrangements. NRLP's proposal is appropriate for the following reasons:

[2] OEB Filing Requirements for Electricity Transmission Applications Chapter 2, February 11, 2016, p 1.

- NRLP owns and operates a single 230kV transmission asset that was just recently placed in service and thus has several decades before substantial capital spending will be required.;

- NRLP's main controllable cost is OM&A (there are no forecast capital expenditures). These costs are a small fraction of total costs (less than 10% of Revenue Requirement) and are significantly less than the non-controllable portions of NRLP's costs (Cost of Capital, Depreciation, Income Tax). Therefore, cost efficiencies are available only in respect of a modest portion of the overall Revenue Requirement;[3]

- NRLP's management and work programs are provided by a service level agreement, resulting in minimal overhead as well as access to qualified and flexible resources when needed, allowing NRLP to remain cost-efficient; and

- NRLP's service level agreement integrates Hydro One Networks Inc.'s productivity improvements into NRLP's maintenance operations.

## 1.3 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the RCI by component that NRLP is proposing to use to determine the total revenue requirement for rate-making purposes for 2021 through 2024

[3] In addition, preparing a benchmarking report would yield results of limited value. Such a benchmarking report would require a high degree of customization to provide comparables to NRLP, including for example the removal of capital costs, facilities, stations and lines (115kV and 500kV) costs, among other things.

**Table 2 - Revenue Cap Index (RCI) by Component (%)**

| **Revenue Cap Index by Component** | **2021** | **2022** | **2023** | **2024** |
|---|---|---|---|---|
| Inflation Factor (I) | 1.4% | 1.4% | 1.4% | 1.4% |
| Productivity Factor (X) | 0.0% | 0.0% | 0.0% | 0.0% |
| **Total Revenue Cap Index** | 1.4% | 1.4% | 1.4% | 1.4% |

The Inflation Factor in Table 2 will be updated annually, as described in section 1.1 of this Exhibit. NRLP proposes that the Productivity Factor will remain unchanged throughout the IR term. Table 3 below summarizes the Total Revenue Requirement that would result, were the Application to be approved as filed.

**Table 3 - Revenue Requirement by Year**

| **Year** | **Formula** | **Revenue Requirement** |
|---|---|---|
| 2020 | Cost of Service | $ 9.39 million |
| 2021 | 2020 Base Revenue Requirement* x 1.014** | $ 9.52 million |
| 2022 | 2021 Base Revenue Requirement* x 1.014 | $ 9.65 million |
| 2023 | 2022 Base Revenue Requirement* x 1.014 | $ 9.79 million |
| 2024 | 2023 Base Revenue Requirement* x 1.014 | $ 9.93 million |

** Calculations assume the RCI in Table 2.*
*** Exhibit E, Tab 1, Schedule 1, Table 1: To be updated reflecting the actual market rate of the cost of long-term debt after debt refinancing has been completed.*

## 1.4 ADDITIONAL IR FEATURES

NRLP is proposing the following additional features in this Application to provide an additional element of protection for Ontario ratepayers.

### 1.4.1 EARNINGS SHARING MECHANISM (ESM)

NRLP proposes to share, with customers, 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Revenue Cap IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of NRLP's next rebasing.

The calculation of the actual ROE for a Test year will use the OEB-approved mid-year rate base for that period.

### 1.4.2 Z-FACTOR

NRLP is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available over the term of this Revenue Cap IR Application. This is consistent with the principles of the RRFE. The criteria that would apply to the use of the Z-factor mechanism are those outlined by the OEB in Chapter 2 of the Filing Requirements for Electricity Transmission Applications and the guidelines provided in section 2.6 of the OEB's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (July 14, 2008).

Events that may necessitate the use of the Z-factor mechanism include:

- Extreme weather events, such as storms;
- Investments that are government-mandated or otherwise outside of management's control;
- Changes to IESO market rules;
- Changes to OEB codes, policies or other directions;
- Changes to accounting frameworks or technical standards;
- Changes to government policy, legislation, or regulation, such as environmental laws; and
- Any other one-time or ongoing events that meet the Z-factor criteria.

### 1.4.3 OFF-RAMPS

NRLP proposes to apply the OEB's existing policy with respect to off-ramps. The Handbook states that although the purpose of incentive regulation is to drive productivity improvements within the utility, customers must also be protected from utility earnings that become excessive. NRLP is proposing to adopt the OEB's existing off-ramp mechanism, a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review of the Revenue Requirement arising from NRLP's IR may be initiated.

## 2. PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

NRLP expects to file annual update applications in 2021, 2022, 2023 and 2024. These applications are expected to be filed by the deadline for electricity distribution IRM applications seeking a January 1st effective date, which has typically been near the end of August. These applications would calculate the revenue requirement by using the RCI to reflect the most up to date Inflation Factor, as described in section 1.1 and provide revised Uniform Transmission Rate calculations that reflect the revised revenue requirement.

As described above, NRLP proposes that the application in 2021 would also update the cost of long-term debt to reflect the market rate associated with NRLP's new debt instrument(s).

In the event that deferral and variance account balances accumulated in subsequent years are material, NRLP may also seek to dispose of any balances in its annual update applications.

# DESCRIPTION OF THE PARTNERSHIP

Niagara Reinforcement Limited Partnership ("NRLP") is a limited partnership formed under the laws of Ontario. NRLP owns 76 km of 230kV double circuit high-voltage transmission line located in southern Ontario in the Niagara region connecting Allanburg Transformer Station and Middleport Transformer Station. These circuits are referred to as Q26M and Q35M. The business carried out by NRLP is the provision of electricity transmission service in Ontario.

Hydro One Networks Inc. ("HONI") has signed an agreement with Six Nations of the Grand River Development Corporation ("SNGRDC"), and Mississaugas of the Credit First Nation ("MCFN"); two First Nations located proximate to the line. This agreement was formed to enable SNGRDC and MCFN to purchase, an equity interest in the Licenced Applicant, NRLP, as limited partners. The OEB approved NRLP as a licenced transmitter and the transfer of assets from HONI to NRLP under separate dockets, EB-2018-0276 and EB-2018-0277, respectively.

Hydro One Indigenous Partnerships GP Inc. ("HOIP") is the general partner and is responsible for ensuring that the transmission assets owned by NRLP are operated and maintained in accordance with all applicable regulatory standards and HONI's maintenance and operating practices through a comprehensive services agreement, as further outlined in Exhibit F, Tab 3, Schedule 1. The agreement mandates that HONI shall ensure that all applicable OEB licence, code and rule requirements are observed.

The organization chart for the NRLP shareholder structure and financial ownership structure is shown in Figure 1.

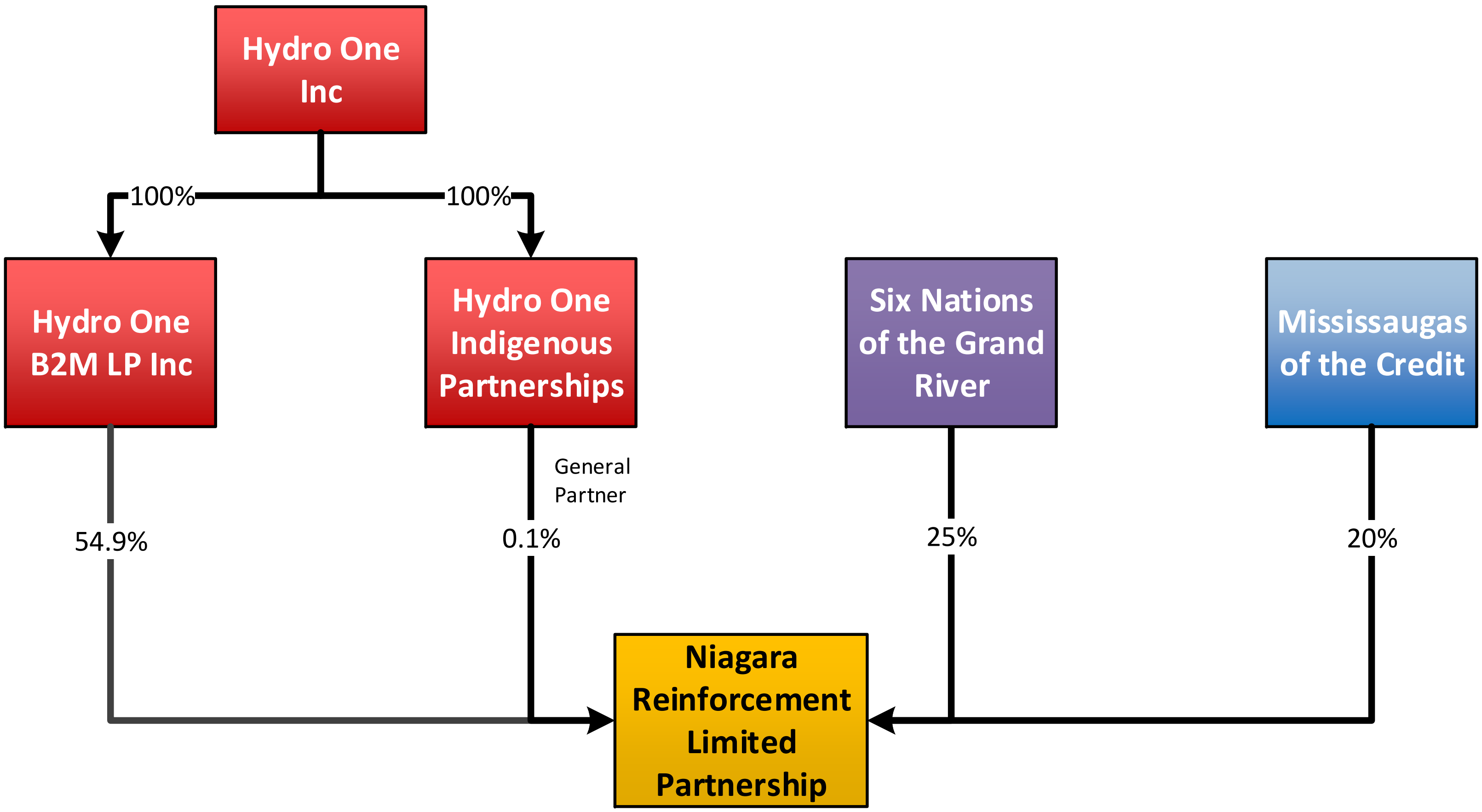


**Figure 1 - Organization Chart for the NRLP Shareholder Structure**

# FINANCIAL INFORMATION

## 1. ACCOUNTING STANDARD

NRLP is seeking permission to adopt United States Generally Accepted Accounting Principles ("US GAAP") as its accounting standard for the purpose of rate setting, regulatory accounting, and regulatory reporting as authorized under section 74 of the Act.

In this regard, NRLP relies on the following provision of the Act:

i. Subsection 70(1), which states that a licence under Part V of the OEB Act may prescribe the conditions under which a person may engage in an activity set out in section 57 and such other conditions as are appropriate having regard to the objectives of the Board and the purpose of the Electricity Act, 1998; and
ii. Subsection 70(2), which provides examples of conditions that may be included in a licence, one of which, as set out in paragraph (f), is a condition requiring the licensee to maintain specific accounting records or to prepare accounting recordings according to specified principles.

Both HONI's distribution and transmission businesses have received OEB approval to utilize US GAAP as its approved framework for rate setting, regulatory accounting and regulatory reporting. Approval to use US GAAP for NRLP will facilitate Hydro One Inc.'s consolidated reporting for securities filing purposes, thus avoiding incremental costs and/or reduced productivity.

## 2. ACCOUNTING ORDERS

NRLP has provided a description of NRLP's regulatory accounts in Exhibit H, Tab 1, Schedule 1.

# NRLP FINANCIAL STATEMENTS - HISTORICAL YEARS

NRLP is a newly formed partnership and, as a result, there are no historical financial statements to include in this application.

# RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2018)

NRLP is a newly formed partnership. Consequently, there is no evidence to provide for this schedule.

# HYDRO ONE LIMITED - HISTORICAL YEAR ANNUAL REPORT (2018)

Included in this Exhibit as Attachment 1 is Hydro One Limited’s 2018 Annual Report.

Filed: 2019-10-25
EB-2018-0275
Exhibit A-6-4
Attachment 1
Page 1 of 114

# Powering economies, connecting communities

# Corporate Profile

We are Ontario's largest electricity transmission and distribution provider with almost 1.4 million valued customers, almost $25.7 billion in assets and 2018 annual revenues of almost $6.2 billion. Our team of approximately 8,600 skilled and dedicated employees proudly build and maintain a safe and reliable electricity system which is essential to supporting strong and successful communities. In 2018, Hydro One invested almost $1.6 billion in its 30,000 circuit kilometres of high-voltage transmission and 123,000 circuit kilometres of primary distribution networks and injected approximately $1.3 billion into the economy by buying goods and services in Ontario. We are committed to the communities where we live and work through community investment, sustainability and diversity initiatives. We are one of only six utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association. Through Hydro One Telecom Inc.'s extensive fibre optic network, we also provide advanced broadband telecommunications services on a wholesale basis. Hydro One Limited's common shares are listed on the Toronto Stock Exchange (TSX: H).

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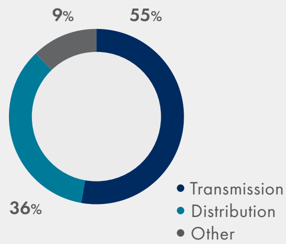
# Financial Highlights

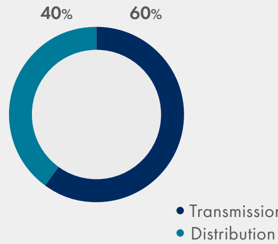
**Total Assets**

**$25.7b**




**Rate Base**

**$19.7b**




**Total Shareholder Return (TSR)**[1]

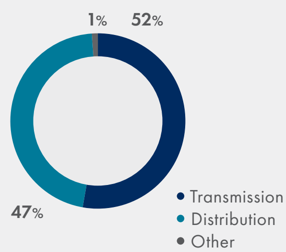
January 1, 2018 to December 31, 2018


[1] Source: Bloomberg

**Revenues**

**$3,251m**

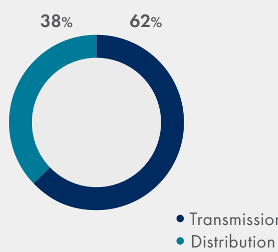
(Net of purchased power costs)




**Regulated Earnings**

**$1,368m**

(Before financing charges and income taxes)




| Year ended December 31 (millions of dollars, except as otherwise noted) | **2018** | 2017 |
|---|---|---|
| Revenues | **6,150** | 5,990 |
| Purchased power | **2,899** | 2,875 |
| Revenues, net of purchased power[1] | **3,251** | 3,115 |
| Operation, maintenance and administration (OM&A) costs | **1,105** | 1,066 |
| Depreciation, amortization and asset removal costs | **837** | 817 |
| Financing charges | **459** | 439 |
| Income tax expense | **915** | 111 |
| **Net income (loss) attributable to common shareholders of Hydro One** | **(89)** | **658** |
| Basic earnings per common share (EPS) | **($0.15)** | $1.11 |
| Diluted EPS | **($0.15)** | $1.10 |
| Basic adjusted non-GAAP EPS (Adjusted EPS)[1] | **$1.35** | $1.17 |
| Diluted adjusted EPS[1] | **$1.35** | $1.16 |
| Net cash from operating activities | **1,575** | 1,716 |
| Funds from operations (FFO)[1] | **1,572** | 1,579 |
| Capital investments | **1,575** | 1,567 |
| Assets placed in-service | **1,813** | 1,592 |
| Transmission: Average monthly Ontario 60-minute peak demand (MW) | **20,485** | 19,587 |
| Distribution: Electricity distributed to Hydro One customers (GWh) | **27,338** | 25,876 |
| Debt to capitalization ratio[2] | **55.6%** | 52.9% |

Note: All amounts are in Canadian dollars unless otherwise specified.

[1] See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been presented at December 31, 2018 and 2017, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

This report contains forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our Company. Words such as "expect" and "will" are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

POWERING ECONOMIES, CONNECTING COMMUNITIES

# Year in Review

### SAFETY COMES FIRST

- Through Hydro One's *Journey to Zero* safety initiative, we achieved our 2018 performance target rate for recordable safety incidents of 1.1 per 200,000 hours worked – a 35% improvement since 2015.

### DRIVING DOWN COSTS

- Productivity savings of $249.9 million since 2015.
- Annual operating costs have been reduced by 4% or $41 million since 2015, resulting in savings[1].
- New approach to storm preparation has reduced the time customers are without power following a storm by one-third, compared to similar-sized events five years ago.

### DELIVERING CUSTOMER SATISFACTION

- Residential and small business customer satisfaction was the highest in five years at 76%, while transmission customer satisfaction reached an all-time high of 90%.
- Billing accuracy reached an all-time high of 99.4%, while overdue accounts receivable fell to $73 million – less than half of 2015.
- Repatriating approximately 400 Customer Contact Centre employees back into our business has improved customer service and reduced costs.

### IMPROVING THE GRID

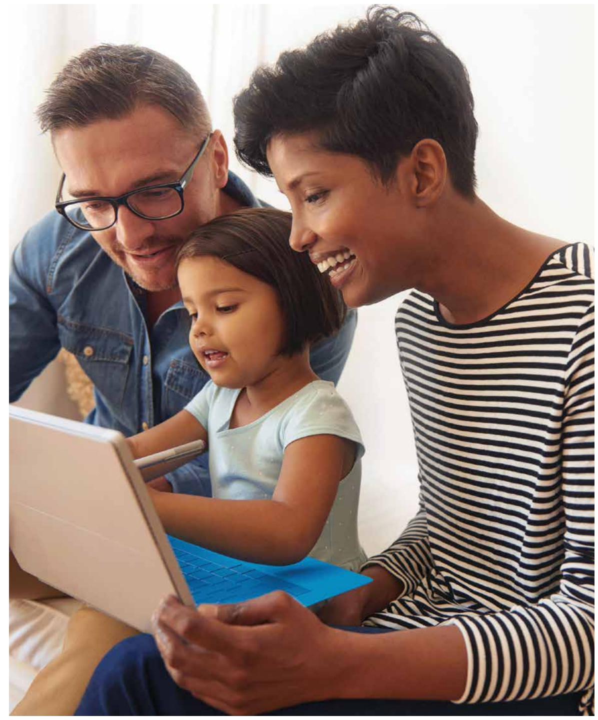
- Compared to 2017, we improved the overall reliability of our distribution network by 14.2%.
- Clarington ($238 million in capital costs) and Leamington ($54 million in capital costs) stations were placed into service with strong project and cost discipline to support economic growth.
- More than $1.8 billion of assets placed in-service in 2018.

### LEADERSHIP IN POWER RESTORATION

- Three Edison Electric Institute (EEI) Emergency Recovery Awards for outstanding power restoration efforts in Ontario and one Emergency Assistance Award for providing restoration support in the northeast U.S.
- Two teams of forestry technicians sent to Chico, California to support electrical system restoration efforts following devastating wildfires[2].
- Following a tornado that destroyed the company's Merivale transmission station, Ottawa-area customers were restored within 48 hours with a temporary solution. The facility was fully rebuilt in approximately 12 weeks, returning to normal operation.

[1] Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding $31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement have been paid for by Ontario ratepayers.
See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

[2] All costs incurred during mutual assistance operations are paid by the local utility receiving support.



## Powering Communities

**$1.3b**

**Goods and services procured in Ontario**

**63%**

**Increase in spending with Indigenous businesses since 2017**

**8,600**

**Regular and non-regular employees (approximate) across the province averaged over 2018**

**$2.6m**

**In sponsorships and donations in communities where our customers work and live**

**$1.3m**

**Donated by our employees and pensioners to charitable organizations**

# Tom Woods

Hydro One's mandate is to deliver exceptional customer service and a safe and reliable source of electricity to homes and businesses in every community we serve.

The critical nature of our work directly translates to jobs, economic development, confidence and prosperity in cities and towns across the province.

In 2018, Hydro One transitioned to a new Board of Directors and I want to take this opportunity to officially welcome its new members: Cherie Brant, Blair Cowper-Smith, Anne Giardini, David Hay, Timothy Hodgson, Jessica McDonald, Russel Robertson, William Sheffield and Melissa Sonberg. This independent, highly-qualified Board has strong governance and industry experience as well as significant electricity, business and capital markets expertise.

Guided by its executive team, our introduction to Hydro One was seamless, efficient and comprehensive, enabling the Board to fully engage in all areas of the organization. We were reassured and indeed energized by the fundamental strength of the organization, the depth of its leadership and the resiliency of its employees in staying focused on the core business during a transitional year.

One of the top priorities for the Board is recruiting a new President and CEO. We have strict criteria for selecting this individual as they will be expected to lead the business to great heights.

Hydro One leadership will be accountable for achieving challenging performance targets by remaining focused on delivering exceptional customer service, driving efficiencies, improving the reliability of the electricity system and delivering strong financial performance for the benefit of shareholders and all Ontarians.

The Board will continue to provide strong oversight, guide forward-looking business strategies and commit to pursuing sustainability to secure the long-term viability of a well-run Hydro One. The company has a proud 100-plus year history, a dedicated team, and a solid foundation built with robust business fundamentals.

**Tom Woods**
Chair of the Board of Directors

As we transform our business to meet the challenges of tomorrow, we will nurture Hydro One's results-oriented culture and pursue opportunities to innovate, be more efficient and provide exceptional customer service every day. We will be guided in these pursuits by Hydro One's commitment to continuous improvement, our "customer comes first" philosophy and the strength of our employees at all levels of the organization.

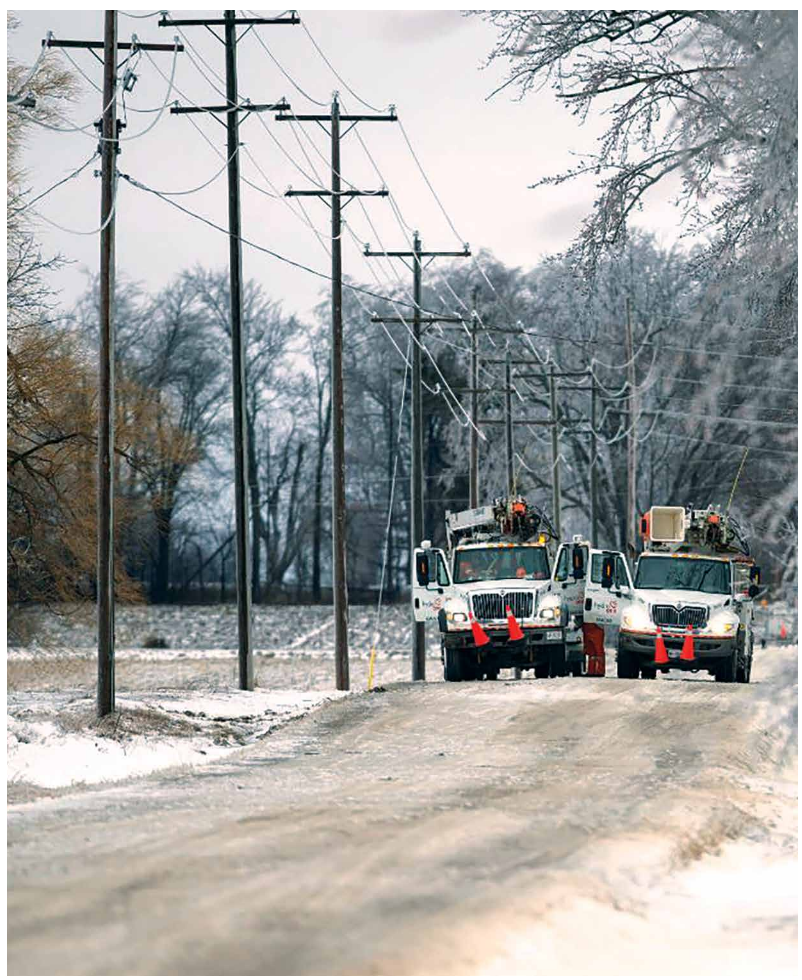
I want to thank our employees for their hard work and coming together through this period of leadership transition. Your commitment and willingness to go the extra mile to meet the needs of our customers have helped us build a stronger and better company.

Hydro One will continue to play a critical role in powering economies and connecting communities across this province. We remain dedicated to delivering greater value for our customers, employees, communities and all shareholders.

On behalf of the entire Board of Directors, thank you for your investment and ongoing support of Hydro One.

With best regards,

Tom Woods
Chair of the Board of Directors



A MESSAGE FROM THE ACTING PRESIDENT & CEO

# Paul Dobson

Hydro One seeks excellence in every facet of our business, to the benefit of our customers, employees, communities and all shareholders. This approach became immediately clear to me after joining the organization in early 2018 and was further driven home in the sense of pride I felt being a part of a high-performance team that accomplished tremendous feats in a challenging year.

### Safety

Hydro One's safety performance was a top priority for management in 2018. Following the tragic loss in late 2017 of four Hydro One team members, we heightened our resolve to realize a vision of an injury-free workplace through our *Journey to Zero* initiative.

### Operational Excellence

Driving improvements in network reliability last year resulted in a 14.2% improvement in total average power outage duration for our distribution system over 2017. This is attributed to our application of modern technology to the grid, new storm prediction tools that allow for improved restoration response and our state-of-the-art vegetation management program.

In fact, this new vegetation process is an example of how the company is increasing productivity, driving costs down and generating efficiencies to improve our service to customers. In 2018, our forestry teams completed approximately 30,000 kilometres of work along power lines, nearly three times the work they did in 2017, with only a marginal increase in cost.

While we saw results drop for transmission reliability due mainly to highly abnormal weather, the quick, effective and innovative responses deployed by our crews to these events was laudable. For example, after our Merivale transmission station was destroyed by a tornado in late September, a temporary solution was implemented within 48 hours to return service to customers and the facility was rebuilt in just 12 weeks.

### Customer

Due to a renewed effort to improve customer service and reliability in addition to other initiatives, residential and small business customer satisfaction, as well as transmission customer satisfaction reached the highest in five years and company history, respectively, in surveys last year. These results demonstrate a consistent dedication to putting customers first at all levels of the organization.

We actively seek to learn what is important to our customers and take action. For example, we repatriated approximately 400 employees in our Customer Contact Centre to provide better service and we conducted countless face-to-face meetings with customers to identify ways we can facilitate growth and strengthen local economies. Our First Nations outreach efforts also demonstrated ongoing efforts to support all customers' needs. In 2018, we met with the 88 Indigenous communities we serve and held over 700 one-on-one customer sessions.

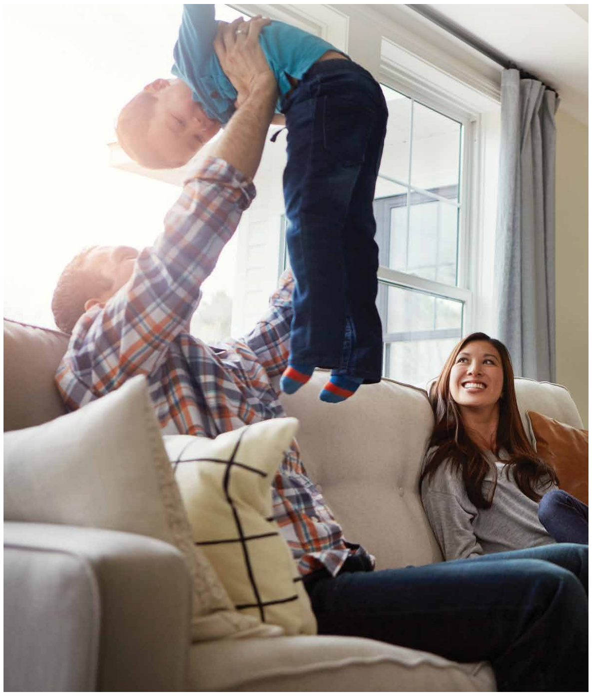
**Paul Dobson**
Acting President and CEO

### Economy

Our transmission system serves as the backbone for the economy, and our business plays a critical role in communities across the province. In 2018 alone, we injected approximately $1.3 billion into the Ontario economy by buying goods and services from businesses across the province, including a 63% increase in spend with Indigenous businesses, as well as directly providing approximately 8,600 highly skilled jobs through the year.

### Avista

While we were naturally disappointed in the outcome of the Avista transaction, we will continue to pursue opportunities that make sense for our business and add value for all stakeholders.



**Employees**

In January, we were honoured to be recognized by Forbes in its list of Canada's Best Employers for 2019. Based on a survey of over 8,000 people working at Canadian businesses with over 500 employees, our performance demonstrates efforts to create an engaged workforce and positive working environment.

In 2019, we will maintain our focus on continuous improvement and operational excellence, delivering efficiencies and exceptional customer service.

Finally, I would like to thank all teammates for their resilience and support during the leadership transition and for their dedication to driving improvements across the Hydro One business. I would like to thank the Board for their efforts during the transition.

Sincerely,

Paul Dobson
Acting President and CEO

## Key Achievements

**$249.9m**
Productivity savings since 2015

**14.2%**
Improvement in the overall reliability of our distribution network since 2017

**4% or $41m**[1]
Reduction in annual operating costs since 2015

**$1.3b**
Injected into the Ontario economy through purchases of local goods and services

**90%**
Highest-ever satisfaction rating from transmission customers

**4**
Edison Electric Institute Awards earned in 2018 for emergency power restoration

**76%**
Residential and small business customer satisfaction, highest in 5 years

## Addressing Ontario's Aging Power Infrastructure

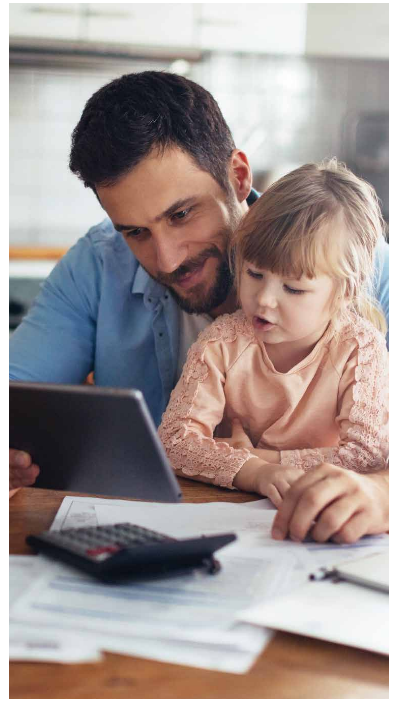
A safe and reliable high-voltage transmission system is necessary to run and grow the large industrial companies, mines and manufacturing facilities that create job opportunities in Ontario.

Much of our system was built in the 1950s. One in four transformers are at the end of their expected service life, and nearly 10,000 of our steel towers are over 80 years old. To keep the public safe and reduce the number of power outages that can impact the economy and our customers' lives, we must invest in replacing, repairing and upgrading equipment in almost every community.

[1] Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding $31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement will be paid for by Ontario ratepayers. See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

# Strategic Approach

## We aim to continue strengthening our core business in order to deliver greater value for our customers, employees, communities and shareholders.



**OUR STRATEGIC PILLARS:**

**Customers First:**
Exceeding our customers' needs and expectations is at the core of everything we do. We are focused on improving our customers' experience through fast, flexible and convenient service.

**Cost Efficiency:**
We are committed to investing carefully, reducing costs and stretching every dollar we spend to efficiently help the most customers.

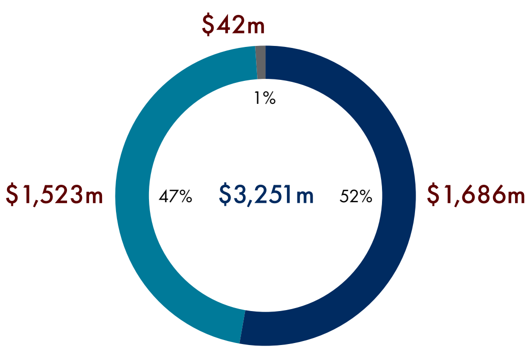
**Operational Excellence:**
A continuous drive to improve our transmission and distribution networks means we are constantly raising performance and standards.

**Investing in our Future:**
Invest in innovation to improve service reliability, the efficiency of our business and the long-term viability of the company. We will expand our rate base, pursue organic growth and innovate for the benefit of stakeholders.

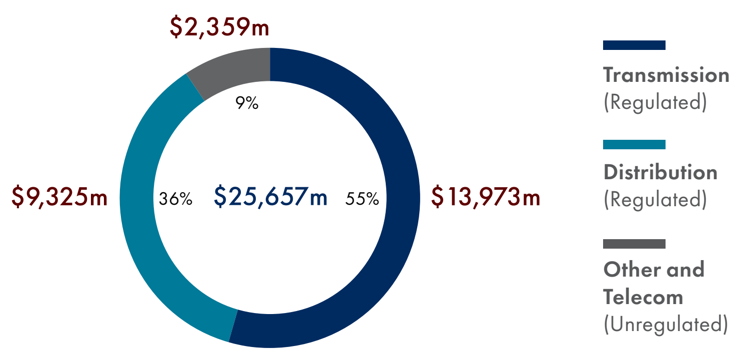
**Sustainability:**
We understand that improving our performance depends on incorporating sustainability into all aspects of our business.

## Our Business: At-a-Glance

**Revenues (net of Purchased Power)**

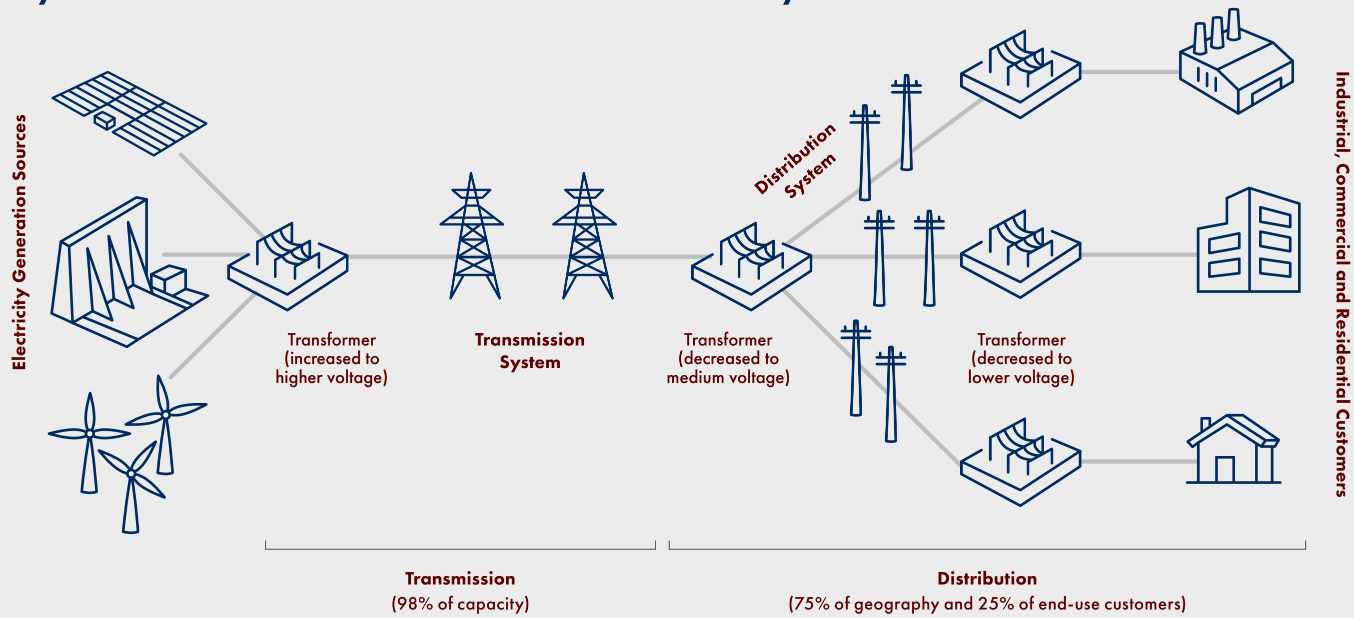



**Segmented Assets**




| | Transmission | Distribution | Other and Telecom |
|---|---|---|---|
| **Business Description** | Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to our distribution company and industrial customers across Ontario. Hydro One owns and operates approximately 30,000 circuit kilometres of high-voltage transmission lines. | The Hydro One distribution system is the largest in Ontario. It consists of approximately 123,000 circuit kilometres of primary low-voltage power lines serving almost 1.4 million customers. As well, Hydro One Remote Communities serves customers in one grid-connected and 21 off grid communities in Ontario's far north. | Consists of a telecommunications business and certain corporate activities. Hydro One Telecom offers organizations a diverse, secure and highly reliable broadband connectivity solution. |
| **Customer Segments** | • Large directly connected industrial customers<br>• Local distribution companies<br>• Large generators | • Residential and business customers<br>• Municipal utility customers<br>• Small or micro generators | • Data centres<br>• Cloud service providers<br>• Telecommunications services and public sector entities<br>• Internet service providers<br>• Enterprises |

## Hydro One's Role in the Ontario Electric Power System



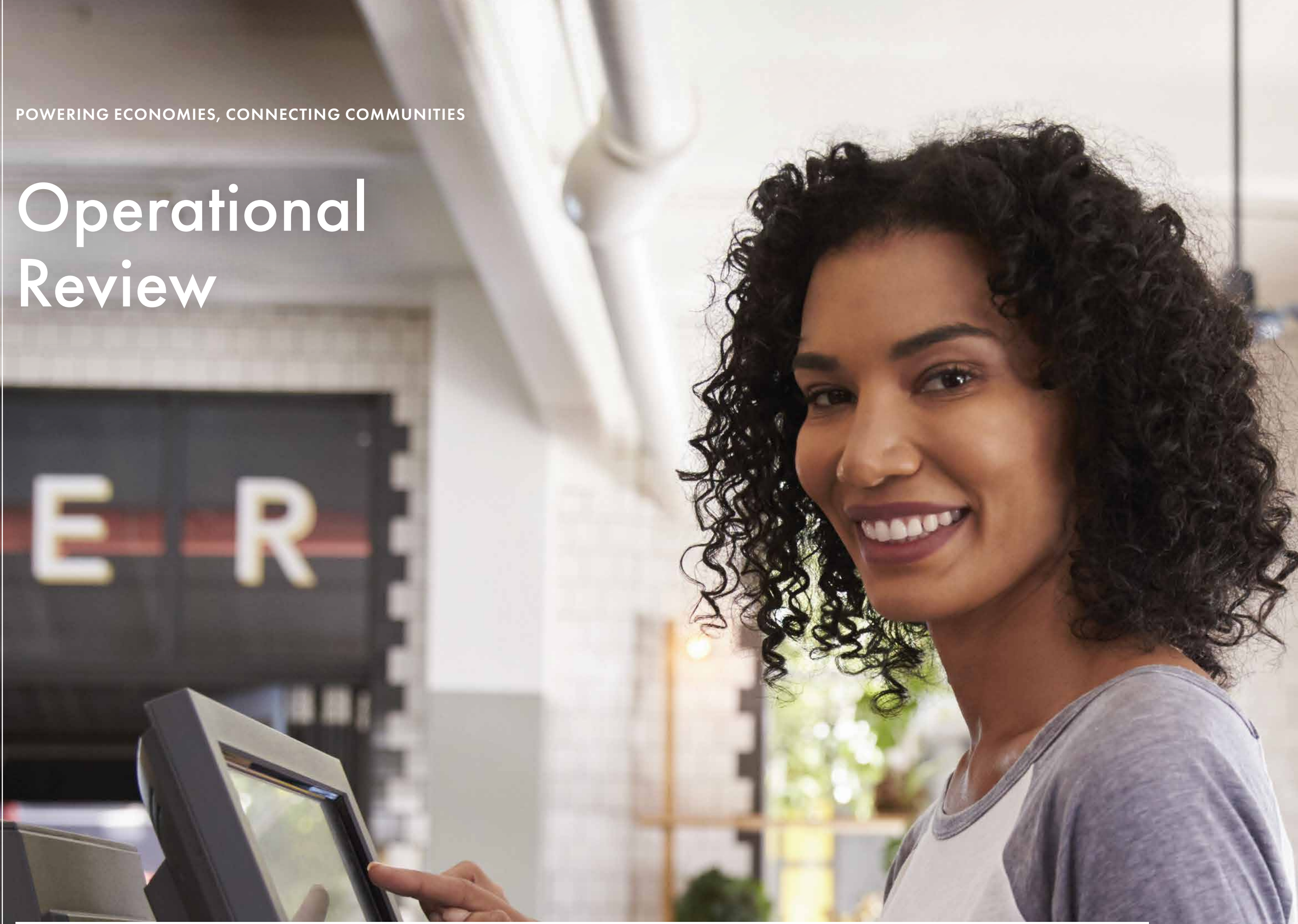

Our transmission and distribution systems safely and reliably serve communities throughout Ontario. Our customers are suburban, rural and remote homes and businesses across the province. We own and operate nearly $25.7 billion in assets and have annual revenues of almost $6.2 billion. Our communities are proudly and safely serviced by a team of skilled and dedicated employees.

## Major Projects

| | Niagara Reinforcement Project | Richview Transmission Station | East-West Tie Station Expansion |
|---|---|---|---|
| |  |  |  |
| | A new 76 kilometre transmission line in southwestern Ontario to serve the growing Niagara area. | Replacement of 50-year-old equipment to ensure reliable power supply to the City of Toronto and surrounding communities. | Hydro One is performing station upgrades to our Lakehead, Marathon and Wawa transmission stations. The upgrades are necessary to support the East-West Tie Line project, a priority project in the Province of Ontario's Long-Term Energy Plan. |
| Estimated Total Project Cost ($ millions) | $130 | $102 | $157 |
| Capital Cost to-date ($ millions) | $121 | $99 | $16 |
| Anticipated In-service Date | 2019 | 2020 | 2022[1] |

[1] The majority of the project will be in-service in 2021, enabling the connection and energization of the new East-West Tie transmission line. Additional work to complete the upgrades will be in-service in 2022.

# Operational Review




## Putting our Customers First

**We delivered a number of far-reaching initiatives that focused on what is best for our customers.**

Insourcing approximately 400 employees to our Customer Contact Centre has improved customer service and reduced costs, while our redesigned bill is easier for customers to understand.

Proactive measures to help customers who are behind on their bills, while avoiding disconnections wherever possible, have reduced overdue accounts receivable by half – down to $73 million from $148 million in 2015.

Our customer care team also increased Hydro One's presence in First Nation communities across the province, conducting face-to-face meetings with customers and offering measures to address affordability.

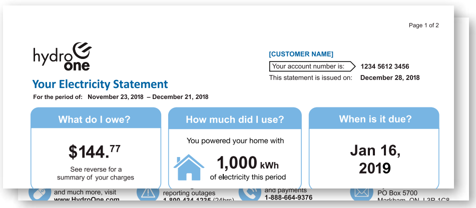
A relentless focus on customer service resulted in improved satisfaction survey scores. Residential and small business customer satisfaction was the highest in five years at 76%, while transmission customer satisfaction reached an all-time high of 90%, reflecting a company-wide dedication to improving customer service.

### Energy Conservation

We achieved 92% of our six-year energy conservation target in only four years. Our energy conservation team conducted over 1,250 visits with our medium to large commercial and industrial customers and supported over 800 energy efficiency projects during the year.

### Billing Accuracy (%)


### Overdue Accounts Receivable ($ millions)


Right:
Hydro One's redesigned residential bill has improved customer comprehension and reduced calls to the company's Customer Contact Centre.

## Stretching Every Dollar

### We strive to do more for less

Since 2015, Hydro One has cut operation, maintenance and administrative (OM&A) costs by 4% – or $41 million[1] – through efficiencies, new technology and other cost-saving initiatives.

Productivity savings of $135.5 million in 2018 brings the total saved since 2015 to $249.9 million. The top productivity savings in 2018 are from procurement initiatives, fleet rationalization, contract negotiations in information solutions and cable locate outsourcing.

### Streamlining our Work

In 2018, we completed the transition of our vegetation management program from a 10-year to a 3-year cycle, focusing on trimming problem trees and vegetation more often to improve the overall safety and reliability of the system. Our forestry teams completed approximately 30,000 kilometres of work along power lines, nearly three times the work they did in 2017, with only a marginal increase in cost.

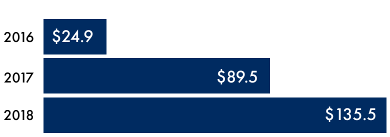
**4%**

**reduction in operating costs since becoming a publicly traded company in 2015[1]**

**3x**

**In 2018, our forestry teams completed nearly three times the work done in 2017, with only a marginal increase in cost**

**Productivity Savings ($ millions)**




**Cumulative: $249.9 million**

[1] Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding $31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement will be paid for by Ontario ratepayers. See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

# Operating with Excellence

**We made significant progress in improving Hydro One's safety performance, achieving our 2018 target of 1.1 recordable injuries per 200,000 hours worked – a 35% improvement since 2015. We have a commitment to an injury-free workplace through our *Journey to Zero* initiative, which focuses on enhancing personal leadership in order to reduce workplace hazards.**

The large number of severe weather events in 2018 resulted in five Force Majeure incidents[1]. Three incidents were within six weeks of each other, requiring crews to restore power to over 1.4 million customers in aggregate – more than all of 2017.

## Our Distribution Network

We improved the overall reliability of our distribution network by 14.2% compared to 2017. These improvements included more system oversight, our new vegetation management program, modernizing equipment, being more proactive in preparing for storms and targeting equipment upgrades to circuits that were causing the most power outages.

## Our Transmission Network

While transmission reliability and outage duration results dropped slightly during the year, mainly due to major equipment failures and severe weather, crews worked tirelessly to quickly and safely restore power.

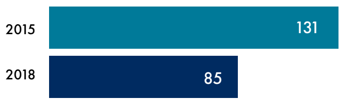
We experienced significant events at our Gerrard, Minden and Finch stations. Further, our Merivale station was destroyed by a tornado in late September. While customers were restored within 48 hours with a temporary solution, the facility required 12 weeks of extensive work to rebuild.

Merivale Transmission Station near Ottawa after a tornado destroyed the facility on September 21, 2018.

### WORKPLACE SAFETY

## 35%

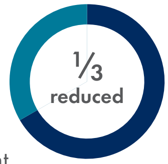
Improvement in recordable workplace injuries since 2015.




### CUSTOMER SERVICE

## Improved Restoration Time

- We have reduced the time customers are without power following a storm by one-third since a similar-sized event five years ago.




- The overall reliability of our distribution network improved by 14.2% compared to 2017.


[1] Hydro One deems a Force Majeure to have occurred when electricity service to 10% or more of our distribution customers has been interrupted by an event.

## Investing in our Future

**We invest in technology and infrastructure modernization to ensure our business evolves and grows to meet the needs of our customers.**

In 2018, we made total capital investments of approximately $1.6 billion to ensure the long-term reliability of Ontario's electricity system and placed more than $1.8 billion worth of new assets in-service. We completed one of the largest-ever station builds in company history, bringing the flagship Clarington Station into service on-time and under budget. The Leamington station was also brought into service as planned.

### Pursuing Organic Growth

In 2018, we successfully integrated Hydro One Sault Ste. Marie LP into our Hydro One Networks operations. As well, we announced an agreement to acquire the business and distribution assets of Peterborough Distribution Inc. and have submitted a new application with the Ontario Energy Board to acquire Orillia Power Distribution Corporation.

**200+**
**new apprentices hired in 2018**

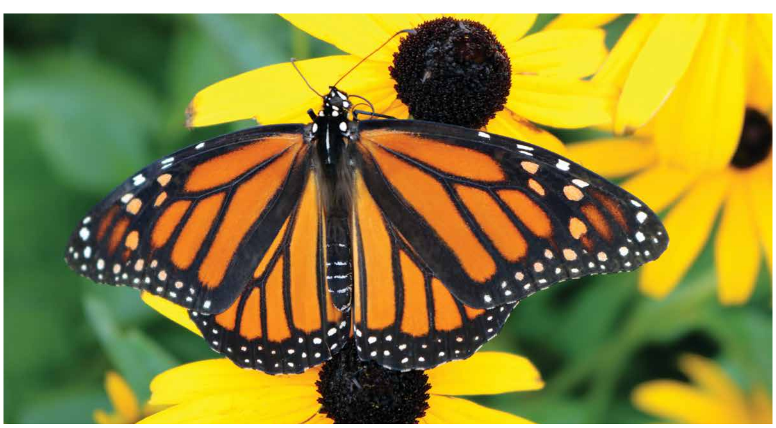
**$6.5b**
**of assets placed in-service over the last 4 years**

### Investing for Tomorrow

Not only do our investments maintain the safety and integrity of our system, they also contribute to local communities by creating jobs, new skills and new opportunities. In 2018, we hired over 200 apprentices into skilled trades, representing a renewal of our workforce.

# Sustainability

At Hydro One, we understand that our long-term performance depends on incorporating sustainability into all aspects of our business. In 2018, we continued building our sustainability strategy, and remain committed to setting up a corporate-wide vision and program that builds value for all stakeholders.



**3 hectares**

**Approximate size of new pollinator planting established to help restore monarch butterfly habitats**

## Environmental Management

Hydro One seeks to avoid or minimize its impact on the environment because we understand this supports business interests and our commitment to being a sustainable company. We deliver electricity that is among the cleanest in North America.

Partnerships have helped further our biodiversity goals. We established approximately three hectares of new pollinator planting in Ottawa with the Canadian Wildlife Federation as part of a multi-stakeholder project to assess species value resulting from restoration of monarch butterfly habitats. We also collaborated with the Briarbrook Brookside Morgan's Grant Community Association to establish pollinator friendly plots and new management techniques on the community's electricity corridor.

## People and Potential

Hydro One pursues a culture of inclusion because it makes us stronger, more innovative and helps ensure we have the right skill set and perspectives to succeed in the future.

In 2018, while representation of women in executive positions decreased slightly by 0.7% to 36.4%, we were able to increase representation of visible minorities in executive positions to 15.6% from 11.4% in 2017. We advanced our Indigenous hiring plans and will pursue our multi-year plan to enhance future performance.

We celebrated Pride Month for the first time, flying rainbow flags at locations across the province, distributing *I Stand for Inclusion* stickers and creating our "PrideOne Employee Resource Group" for LGBTQ2+ employees and their allies.

We worked with union leadership on the mutually beneficial renewal of a two-year collective agreement with the Power Workers Union, which covers approximately 4,000 employees in critical front-line roles until March 31, 2020.

To better support our employees and pensioners, we refreshed *The Power to Give*, our charitable giving program. Last year, our employees and pensioners generously donated almost $1.3 million.


**$1.3m**

**In donations by employees and pensioners to causes that matter to them**

**OUR PEOPLE**

Hydro One was recognized by Forbes on its list of Canada's Best Employers 2019.

**5,643**

Regular employees[1]

**2,948**

Non-regular employees[2]

## Powering Economies

We support Ontario by buying goods and services from businesses across the province. In 2018, approximately $1.3 billion was injected into the Ontario economy through procurement. This includes a 63% increase in spend since 2017 with Indigenous businesses, the largest amount to date, and supports our goal to become the primary business partner of Indigenous communities in Ontario by 2021.

In 2018, we met with the 88 Indigenous communities we serve and held over 700 one-on-one customer sessions. Following extensive community consultations, we completed the commercial terms on a business partnership with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation on the Niagara Reinforcement Transmission Line Project.

Hydro One has a strong history of giving back to the communities where our people and customers live and work. In 2018, we invested $2.6 million through sponsorships and donations with local programs and activities across the province.

**COMMUNITY INVESTMENT**

Since 2003, Hydro One has been a proud sponsor of the *Little Native Hockey League* tournament, which hosts over 200 teams from First Nations across Ontario. The largest event of its kind in the province, the tournament promotes respect, citizenship, sportsmanship and education with Indigenous youth.

[1] In 2018, Hydro One changed its counting methodology for full-time regular and non-regular employees. Prior year figures referenced employment as at year-end December 31. In 2018, the methodology changed to reflect the average employment throughout the year.

[2] Non-regular includes: temporary and casual employees.

# Why invest in Hydro One?

Investing in Hydro One offers a unique opportunity to participate in the transformation of a large-scale regulated electric utility.

ONE

## Performance-based Culture

Transformation into a commercially-oriented, cost conscious, customer focused organization with a performance culture under Ontario's emerging incentive-based regulation.

TWO

## Stable Operating Environment

Business is predominately (99%) rate-regulated in a constructive, stable, transparent and collaborative regulatory environment.

Resilient workforce in challenging environments.

Fully independent Board.

THREE

## Predictable Growth

Pure-play electric transmission and local distribution company with an aging infrastructure that requires investment and no commodity price exposure.

**$6.5b**

4-year total of capital investment

FOUR

## Attractive Dividend

Stable and growing dividend with a 70–80% target payout ratio[1] that is underpinned by strong cash flows from predictable rate base growth.

FIVE

## Strong Balance Sheet

Solid investment grade balance sheet.

**Credit Profile**

| Rating Agency | Long-Term Debt Rating | Short-Term Debt Rating | Outlook |
|---|---|---|---|
| DBRS Limited | A (high) | R-1 (low) | stable |
| Moody's | Baa1 | Prime-2 | stable |
| S&P | A- | A-1 (low) | negative |

[1] Payout ratio was 67% of Adjusted EPS in 2018

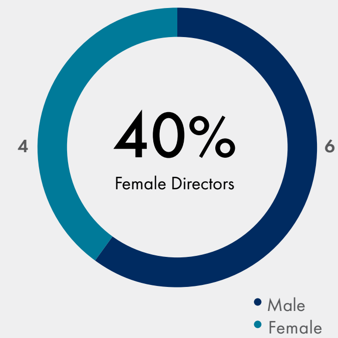
# Corporate Governance

### Board of Directors and Committees

| | Audit | Governance | Human Resources | Health, Safety, Environmental and Indigenous Peoples |
|---|---|---|---|---|
| Tom Woods (Chair) | | | | |
| Cherie Brant | | • | | • |
| Blair Cowper-Smith | | ★ | • | |
| Anne Giardini | • | | | ★ |
| David Hay | • | | | • |
| Timothy Hodgson | | • | • | |
| Jessica McDonald | • | | • | |
| Russel Robertson | • | | • | |
| William Sheffield | ★ | | | • |
| Melissa Sonberg | | • | ★ | |

★ Chair • Committee Member

### Board Diversity




**Strong corporate governance practices are at the heart of how we manage our day-to-day operations in the interest of all stakeholders.**

Hydro One and its independent Board of Directors recognize the importance of corporate governance in the effective management of the Company. Independence, integrity and accountability are the foundation of Hydro One's approach to corporate governance. It is in the long-term best interests of shareholders, and promotes and strengthens relationships with our customers, employees, the communities where we operate and other stakeholders of the Company. The Board of Directors is firmly supported in these commitments by a governance agreement between Hydro One and the province of Ontario, which was executed in advance of the November 2015 Initial Public Offering of the Company and ensures that the province's role is limited to that of a shareholder and not a manager of the business.

Hydro One's Board of Directors is composed of a diverse and accomplished group of independent, proven business leaders with deep corporate governance experience. The Board's primary role is overseeing corporate performance and the quality, depth and continuity of management required to meet the Company's strategic objectives. Hydro One is committed to maintaining best corporate governance practices. The Company's practices are fully aligned with the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

### Board Structure

The Chair is responsible for leading the Board of Directors in carrying out its duties and responsibilities effectively, efficiently and independent of management. The Chair is nominated and confirmed annually by special resolution of the Board. Consistent with best practices, Hydro One's Board Chair is separate from the role of President and Chief Executive Officer and is independent of Hydro One and the province of Ontario.

To learn more about the Directors, committee mandates and composition, go to **www.HydroOne.com/Investors.**


POWERING ECONOMIES, CONNECTING COMMUNITIES

# Financial Report

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# Notice to Reader

Please be advised that Hydro One Limited (Hydro One or the Company) is filing Amended Consolidated Financial Statements and Amended Management's Discussion and Analysis (MD&A) for the period ended December 31, 2018, amending the documents previously filed to reflect the following changes:

1. The Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows and the relevant notes to the Consolidated Financial Statements for Income Taxes, Regulatory Assets and Liabilities, Segment Reporting, and Subsequent Events were updated to reflect the impact of the March 7, 2019 decision issued by the Ontario Energy Board (OEB) relating to the Deferred Tax Asset portion of the OEB's decision on Hydro One Networks' 2017 and 2018 transmission revenue requirement, for which the OEB previously granted a Motion to Review and Vary (DTA Decision) as disclosed in the Audited Consolidated Financial Statements Note 32(D) – Subsequent Events (OEB Regulatory Decisions) and Note 12 – Regulatory Assets and Liabilities.
2. MD&A was updated to reflect the impact of the DTA Decision, including the Consolidated Financial Highlights and Statistics, Overview, Results of Operations, Selected Annual Financial Statistics, Quarterly Results of Operations, Regulation, Non-GAAP Measures, Risk Management and Risk Factors, Summary of Fourth Quarter Results of Operations, Hydro One Holdings Limited – Unaudited Consolidating Summary Financial Information, and Forward-Looking Statements and Information.

The DTA Decision is a Type I subsequent event under United States Generally Accepted Accounting Principles (US GAAP) and as such the Company is required to update the Consolidated Financial Statements and MD&A to reflect the subsequent event in connection with filing its annual reports on Form 40-F with the US Securities and Exchange Commission, so that they contain the current information required at March 25, 2019, the date of approval of the annual report on Form 40-F.

Other than as expressly set forth above, the Amended Consolidated Financial Statements and Amended MD&A do not purport to update or restate the information in the original Consolidated Financial Statements and MD&A or reflect any events that occurred after the date of the filing of the original Consolidated Financial Statements and MD&A other than changes to the sections as expressly set forth above.

The Amended Consolidated Financial Statements and Amended MD&A have been filed electronically at www.sedar.com and at www.sec.gov/edgar.shtml, and also on the Company's website at www.HydroOne.com/Investors.

# Amended Management's Discussion and Analysis

For the years ended December 31, 2018 and 2017

The following Amended Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the amended consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2018. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which can vary from those of the US. This MD&A provides information for the year ended December 31, 2018, based on information available to management as of February 20, 2019, other than with respect to information relating to the subsequent events disclosed in Note 32(D) to the Consolidated Financial Statements, dated March 25, 2019.

## CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

| Year ended December 31 (millions of dollars, except as otherwise noted) | 2018 | 2017 | Change |
|---|---|---|---|
| Revenues | **6,150** | 5,990 | 2.7% |
| Purchased power | **2,899** | 2,875 | 0.8% |
| Revenues, net of purchased power[1] | **3,251** | 3,115 | 4.4% |
| Operation, maintenance and administration (OM&A) costs | **1,105** | 1,066 | 3.7% |
| Depreciation, amortization and asset removal costs | **837** | 817 | 2.4% |
| Financing charges | **459** | 439 | 4.6% |
| Income tax expense | **915** | 111 | 724.3% |
| **Net income (loss) attributable to common shareholders of Hydro One** | **(89)** | **658** | **(113.5%)** |
| Basic earnings per common share (EPS) | **$ (0.15)** | $ 1.11 | (113.5%) |
| Diluted EPS | **$ (0.15)** | $ 1.10 | (113.6%) |
| Basic adjusted non-GAAP EPS (Adjusted EPS)[1] | **$ 1.35** | $ 1.17 | 15.4% |
| Diluted Adjusted EPS[1] | **$ 1.35** | $ 1.16 | 16.4% |
| Net cash from operating activities | **1,575** | 1,716 | (8.2%) |
| Funds from operations (FFO)[1] | **1,572** | 1,579 | (0.4%) |
| Capital investments | **1,575** | 1,567 | 0.5% |
| Assets placed in-service | **1,813** | 1,592 | 13.9% |
| Transmission: Average monthly Ontario 60-minute peak demand (MW) | **20,485** | 19,587 | 4.6% |
| Distribution: Electricity distributed to Hydro One customers (GWh) | **27,338** | 25,876 | 5.7% |

| | 2018 | 2017 |
|---|---|---|
| Debt to capitalization ratio[2] | **55.6%** | 52.9% |

1 See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

2 Debt to capitalization ratio has been presented at December 31, 2018 and 2017, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

## OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the years ended December 31, 2018 and 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| Transmission | 52% | 51% |
| Distribution | 47% | 48% |
| Other | 1% | 1% |

At December 31, 2018 and 2017, Hydro One's business segments accounted for the Company's total assets as follows:

| December 31 | 2018 | 2017 |
|---|---|---|
| Transmission | 55% | 53% |
| Distribution | 36% | 36% |
| Other | 9% | 11% |

### Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The Company's transmission business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM), as well as an approximately 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The transmission business is rate-regulated and earns revenues mainly from charging transmission rates that are approved by the OEB.

| | 2018 | 2017 |
|---|---|---|
| Electricity transmitted[1] (MWh) | 137,436,546 | 132,090,992 |
| Transmission lines spanning the province (circuit-kilometres) | 30,166 | 30,290 |
| Rate base (millions of dollars) | 11,870 | 11,251 |
| Capital investments (millions of dollars) | 985 | 968 |
| Assets placed in-service (millions of dollars) | 1,164 | 889 |

1 Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

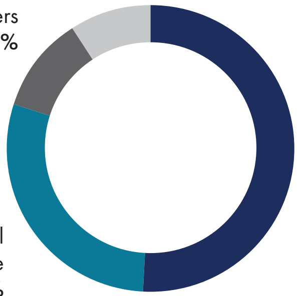
### Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remote Communities). The distribution business is rate-regulated and earns revenues mainly from charging distribution rates that are approved by the OEB.

| | 2018 | 2017 |
|---|---|---|
| Electricity distributed to Hydro One customers (GWh) | 27,338 | 25,876 |
| Electricity distributed through Hydro One lines (GWh)[1] | 38,265 | 36,525 |
| Distribution lines spanning the province (circuit-kilometres) | 123,441 | 123,361 |
| Distribution customers (number of customers) | 1,370,819 | 1,358,093 |
| Rate base (millions of dollars) | 7,852 | 7,389 |
| Capital investments (millions of dollars) | 577 | 588 |
| Assets placed in-service (millions of dollars) | 642 | 689 |

1 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

### 2018 Distribution Revenues




### Other Business Segment

Hydro One's other business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's transmission and distribution businesses, and also offers communications and information technology solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable broadband connectivity. Hydro One's other business segment is not rate-regulated.

## PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

### Transmission Revenues

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

### Distribution Revenues

Distribution revenues include regulated distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

### Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

### Operation, Maintenance and Administration Costs

OM&A costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings and information technology (IT) systems. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

### Depreciation, Amortization and Asset Removal Costs

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Asset removal costs consist of costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

### Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt and short-term borrowings, and gains and losses on interest rate swap agreements, contingent foreign exchange or other similar contracts, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

## RESULTS OF OPERATIONS

### Net Income (Loss)

Net loss attributable to common shareholders for the year ended December 31, 2018 of $89 million is a decrease of $747 million or 113.5% from the prior year. Significant influences on earnings included:

- increase in transmission and distribution revenues due to higher energy consumption resulting from favourable weather;
- higher transmission revenues driven by increased OEB-approved transmission rates;
- higher OM&A costs primarily resulting from:
  - — higher vegetation management costs resulting from a change to an improved vegetation program resulting in greater coverage and better reliability,
  - — higher property taxes, primarily due to non-recurring favourable re-assessment of payments in lieu of property taxes in 2017,
  - — higher project write-offs due to revision of asset replacement strategies and alternatives not pursued, and obsolete inventory and technology, and
  - — higher volume of demand maintenance work on power equipment and overhead lines; partially offset by
  - — savings related to the renewed IT contract, and
  - — lower costs related to the proposed acquisition of Avista Corporation (Merger);
- higher financing charges primarily due to an increase in interest expense incurred on the convertible debentures and short-term notes payable, partially offset by revaluation of the foreign exchange contract related to the Merger; and
- higher income tax expense primarily attributable to a charge to deferred tax expense of $799 million related to the OEB's deferred tax asset and distribution rates decisions, and higher before-tax earnings in 2018, partially offset by higher temporary differences arising from higher in-service additions in 2018, compared to 2017.

### EPS and Adjusted EPS

EPS was ($0.15) in 2018, compared to $1.11 in 2017. The decrease in EPS was driven by lower earnings in 2018, as discussed above. Adjusted EPS, which adjusts for income and costs related to the Merger, including gains and losses on the foreign exchange contract, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses, was $1.35 in 2018, compared to $1.17 in 2017. The increase in Adjusted EPS was driven by higher net income in 2018, as discussed above, but exclude the impact of items related to the Merger and the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses. See section "Non-GAAP Measures" for description of Adjusted EPS.

### Revenues

| Year ended December 31 (millions of dollars, except as otherwise noted) | 2018 | 2017 | Change |
|---|---|---|---|
| Transmission | **1,686** | 1,578 | 6.8% |
| Distribution | **4,422** | 4,366 | 1.3% |
| Other | **42** | 46 | (8.7%) |
| Total revenues | **6,150** | 5,990 | 2.7% |
| Transmission | **1,686** | 1,578 | 6.8% |
| Distribution, net of purchased power | **1,523** | 1,491 | 2.1% |
| Other | **42** | 46 | (8.7%) |
| Total revenues, net of purchased power | **3,251** | 3,115 | 4.4% |
| Transmission: Average monthly Ontario 60-minute peak demand (MW) | **20,485** | 19,587 | 4.6% |
| Distribution: Electricity distributed to Hydro One customers (GWh) | **27,338** | 25,876 | 5.7% |

#### Transmission Revenues

Transmission revenues increased by 6.8% in 2018 primarily due to the following:

- higher revenues driven by increased OEB-approved transmission rates for 2018;
- higher average monthly Ontario 60-minute peak demand driven by colder winter and warmer summer in 2018; and
- increased 2018 allowed return on equity (ROE) for the transmission business.

#### Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 2.1% in 2018 primarily due to the following:

- higher energy consumption resulting from favourable weather in 2018; partially offset by
- lower external revenues in 2018, mainly due to lower late payment charges, connection setup fees and lower storm restorations;
- lower Conservation and Demand Management (CDM) revenue; and
- lower deferred regulatory adjustments, mainly related to the pension cost differential account.

### OM&A Costs

| Year ended December 31 (millions of dollars) | 2018 | 2017 | Change |
|---|---|---|---|
| Transmission | 409 | 375 | 9.1% |
| Distribution | 602 | 593 | 1.5% |
| Other | 94 | 98 | (4.1%) |
| | 1,105 | 1,066 | 3.7% |

**Transmission OM&A Costs**

The increase of 9.1% in transmission OM&A costs for the year ended December 31, 2018 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation in 2017;
- higher volume of work on vegetation management;
- higher project write-offs due to revision of asset replacement strategies and alternatives not pursued; and
- higher volume of demand maintenance work on power equipment and overhead lines; partially offset by
- lower costs related to the renewed IT contract.

**Distribution OM&A Costs**

The increase of 1.5% in distribution OM&A costs for the year ended December 31, 2018 was primarily due to:

- higher volume of work on vegetation management;
- higher volume of emergency calls; and
- higher project and inventory write-offs due to revision of asset replacement strategies, alternatives not pursued, and obsolete inventory and technology; partially offset by
- lower storm restoration costs;
- lower costs related to the renewed IT contract; and
- a lower volume of field collections and investigations as a result of extended winter moratorium.

**Other OM&A Costs**

The decrease in other OM&A costs for the year ended December 31, 2018 was driven by lower consulting and contract costs.

### Depreciation, Amortization and Asset Removal Costs

The increase of $20 million or 2.4% in depreciation, amortization and asset removal costs for 2018 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

### Financing Charges

The increase of $20 million or 4.6% in financing charges for the year ended December 31, 2018 was primarily due to the following:

- a full year of elevated interest expense related to the convertible debentures issued in August 2017; and
- an increase in interest expense on short-term notes payable driven by higher weighted-average interest rates and balance of short-term notes outstanding in 2018; partially offset by
- a decrease in interest expense on long-term debt driven by lower weighted-average interest rate in 2018; and
- an unrealized gain recorded in 2018 due to revaluation of the foreign exchange contract related to the Merger.

### Income Tax Expense

Income tax expense was $915 million for the year ended December 31, 2018, compared to $111 million in 2017. The Company realized an effective tax rate (ETR) of approximately 107.6% in 2018, compared to approximately 14.0% in 2017.

As prescribed by the regulators, the Company recovers income taxes and is required to accrue its tax expense based on the tax liability determined without accounting for temporary differences recoverable from or refundable to customers in the future. The increase in income tax expense for the year ended December 31, 2018 was primarily attributable to a charge to deferred tax expense of $799 million related to the OEB's deferred tax asset and distribution rates decisions (see section "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission" for details). Higher before-tax earnings for 2018, partially offset by increased temporary differences from higher in-service additions in 2018, also contributed to increased tax expense in 2018, compared to 2017.

### Common Share Dividends

In 2018, the Company declared and paid cash dividends to common shareholders as follows:

| Date Declared | Record Date | Payment Date | Amount per Share | Total Amount (millions of dollars) |
|---|---|---|---|---|
| February 12, 2018 | March 13, 2018 | March 29, 2018 | $ 0.22 | 131 |
| May 14, 2018 | June 12, 2018 | June 29, 2018 | $ 0.23 | 137 |
| August 13, 2018 | September 11, 2018 | September 28, 2018 | $ 0.23 | 137 |
| November 7, 2018 | December 11, 2018 | December 31, 2018 | $ 0.23 | 137 |
| | | | | 542 |

Following the conclusion of the fourth quarter of 2018, the Company declared a cash dividend to common shareholders as follows:

| Date Declared | Record Date | Payment Date | Amount per Share | Total Amount (millions of dollars) |
|---|---|---|---|---|
| February 20, 2019 | March 13, 2019 | March 29, 2019 | $ 0.23 | 137 |

## SELECTED ANNUAL FINANCIAL STATISTICS

| Year ended December 31 (millions of dollars, except per share amounts) | **2018** | 2017 | 2016 |
|---|---|---|---|
| Revenues | **6,150** | 5,990 | 6,552 |
| Net income attributable to common shareholders | **(89)** | 658 | 721 |
| Basic EPS | **$ (0.15)** | $ 1.11 | $ 1.21 |
| Diluted EPS | **$ (0.15)** | $ 1.10 | $ 1.21 |
| Basic Adjusted EPS | **$ 1.35** | $ 1.17 | $ 1.21 |
| Diluted Adjusted EPS | **$ 1.35** | $ 1.16 | $ 1.21 |
| Dividends per common share declared | **$ 0.91** | $ 0.87 | $ 0.97[1] |
| Dividends per preferred share declared | **$ 1.06** | $ 1.06 | $ 1.12 |

1 The $0.97 per share dividends declared in 2016 included $0.13 for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

| December 31 (millions of dollars) | **2018** | 2017 | 2016 |
|---|---|---|---|
| Total assets | **25,657** | 25,701 | 25,351 |
| Total non-current financial liabilities | **10,479** | 9,815 | 10,084 |

## QUARTERLY RESULTS OF OPERATIONS

| Quarter ended (millions of dollars, except EPS) | **Dec 31, 2018** | Sep 30, 2018 | Jun 30, 2018 | Mar 31, 2018 | Dec 31, 2017 | Sep 30, 2017 | Jun 30, 2017 | Mar 31, 2017 |
|---|---|---|---|---|---|---|---|---|
| Revenues | **1,491** | 1,606 | 1,477 | 1,576 | 1,439 | 1,522 | 1,371 | 1,658 |
| Purchased power | **741** | 733 | 674 | 751 | 662 | 675 | 649 | 889 |
| Revenues, net of purchased power | **750** | 873 | 803 | 825 | 777 | 847 | 722 | 769 |
| Net income (loss) to common shareholders | **(705)** | 194 | 200 | 222 | 155 | 219 | 117 | 167 |
| Basic EPS | **$ ($1.18)** | $ 0.33 | $ 0.34 | $ 0.37 | $ 0.26 | $ 0.37 | $ 0.20 | $ 0.28 |
| Diluted EPS | **$ ($1.18)** | $ 0.32 | $ 0.33 | $ 0.37 | $ 0.26 | $ 0.37 | $ 0.20 | $ 0.28 |
| Basic Adjusted EPS[1] | **$ 0.30** | $ 0.38 | $ 0.33 | $ 0.35 | $ 0.29 | $ 0.40 | $ 0.20 | $ 0.28 |
| Diluted Adjusted EPS[1] | **$ 0.29** | $ 0.38 | $ 0.32 | $ 0.35 | $ 0.28 | $ 0.40 | $ 0.20 | $ 0.28 |

1 See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing, as well as timing of regulatory decisions.

## CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

### Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | 2018 | 2017 | Change |
|---|---|---|---|
| Transmission | 1,164 | 889 | 30.9% |
| Distribution | 642 | 689 | (6.8%) |
| Other | 7 | 14 | (50.0%) |
| Total assets placed in-service | 1,813 | 1,592 | 13.9% |

#### Transmission Assets Placed In-Service

Transmission assets placed in-service increased by $275 million or 30.9% during the year ended December 31, 2018 primarily due to the following:

- substantial completion of major development work at the Clarington transmission station;
- assets placed in-service in 2018 for station sustainment investments, including Horning, NRC, Centralia, London Nelson, St. Isidore, Wanstead, Mohawk, Palmerston, Chenaux, Dryden, and Bruce A transmission stations, as well as the Bruce Special Protection System end-of-life equipment replacement project;
- higher volume of demand work placed in-service associated with equipment failures;
- higher volume of spare transformers;
- higher volume of overhead lines and component replacement work placed in-service; and
- high volume of work on transmission facilities as a result of a wind storm; partially offset by
- assets placed in-service in 2017 for station sustainment investments, including OverBrook, Hanmer, Aylmer, Leaside, Richview, Goderich, Lakehead, Nepean, and Kirkland Lake transmission stations, as well as DeCew Falls and Hinchinbrooke switching stations;
- substantial investments in major development projects placed in-service in 2017, including the Leamington, Holland, Hawthorne, and Manby transmission stations;
- the completion of the Move-to-Mobile project in June 2017;
- lower volume of wood pole replacements; and
- lower volume of fleet and work equipment purchases.

#### Distribution Assets Placed In-Service

Distribution assets placed in-service decreased by $47 million or 6.8% during the year ended December 31, 2018 primarily due to the following:

- higher volume of sustainment lines carryover work in 2017;
- lower volume of distribution station refurbishments and spare transformer purchases;
- the completion of the Move-to-Mobile project in June 2017;
- lower volume of wood pole replacements;
- the completion of an operation center in Bolton in February 2017;
- lower volume of fleet and work equipment purchases;
- the completion of the Outage Response Management System project in the third quarter of 2017; and
- the completion of the Company's website redesign project in 2017 to improve customer service and operational efficiencies; partially offset by
- higher volume of emergency power and storm restorations work;
- cumulative investments in the Advanced Distribution System project in 2018;
- cumulative investments in distribution generation connection projects in 2018;
- cumulative investments placed in-service for the Source-to-Order Transformation project, which aims to modernize the Company's sourcing and procurement capabilities;
- increased investments placed in-service for meter sustainment work; and
- the completion of the Bill Redesign project, which included investments in application enhancements and software upgrades.

## Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | 2018 | 2017 | Change |
|---|---|---|---|
| **Transmission** | | | |
| Sustaining | **810** | 764 | 6.0% |
| Development | **116** | 137 | (15.3%) |
| Other | **59** | 67 | (11.9%) |
| | **985** | 968 | 1.8% |
| **Distribution** | | | |
| Sustaining | **296** | 280 | 5.7% |
| Development | **217** | 227 | (4.4%) |
| Other | **64** | 81 | (21.0%) |
| | **577** | 588 | (1.9%) |
| **Other** | **13** | 11 | 18.2% |
| **Total capital investments** | **1,575** | 1,567 | 0.5% |

2018 capital investments of $1,575 million were lower than the previously disclosed expected amount of $1,660 million primarily due to:

- re-prioritization of distribution work resulting from the higher volume of storm restoration work, including lower volume of wood pole replacements, lines refurbishment work, distribution system capability projects, and transformer replacements; and
- delayed or deferred projects, including the Integrated System Operations Centre (new site and facility) deferred to future years, deferral of work to 2019 on North American Electric Reliability Corporation (NERC) projects, delays of work to 2019 on the underground cable circuit from Leaside to Main transmission stations, and on the Wanstead, Bronte and Seaton transmission stations; partially offset by
- unplanned work, including the recommencement of Niagara Reinforcement Project, Private Cloud Data Center project, Lake Superior Project, and Advanced Metering Infrastructure initiative; and
- higher volume of storm restoration work.

### Transmission Capital Investments

Transmission capital investments increased by $17 million or 1.8% during the year ended December 31, 2018. Principal impacts on the levels of capital investments included:

- higher volume of overhead lines refurbishments and replacements;
- higher volume of demand work associated with equipment failures;
- higher volume of spare transformer purchases;
- higher volume of work required to adhere to the NERC Critical Infrastructure Protection (Cyber Security) standards; and
- higher volume of IT upgrades and enhancements primarily related to the Private Cloud Data Center project in support of the modernization of Hydro One's IT infrastructure; partially offset by
- lower volume of transmission station refurbishments and replacements work;
- lower spend on load customer connections due to the completion of work at Leamington transmission station in 2017 and higher capital contributions received from customers in 2018;
- the completion of the Move-to-Mobile project in 2017;
- decreased investment in fleet and work equipment purchases as a result of fleet standardization and asset specification review; and
- lower volume of wood pole replacements.

### Distribution Capital Investments

Distribution capital investments decreased by $11 million or 1.9% during the year ended December 31, 2018. Principal impacts on the levels of capital investments included:

- lower volume of distribution lines and station refurbishments and replacements work;
- lower volume of wood pole replacements;
- decreased investment on fleet and work equipment purchases as a result of fleet standardization and asset specification review;
- lower volume of new connections and upgrades;
- lower spend on Advanced Distribution System infrastructures; and
- the completion of the Move-to-Mobile project in 2017; partially offset by
- increased volume of emergency power and storm restorations work due to higher storm activity in 2018;
- higher volume of IT upgrades and enhancements primarily related to the Private Cloud Data Center project in support of the modernization of Hydro One's IT infrastructure; and
- higher spend on joint-use and line relocation projects due to timing of capital contributions.

## Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2018:

| Project Name | Location | Type | Anticipated In-Service Date | Estimated Cost | Capital Cost To Date |
|---|---|---|---|---|---|
| | | | (year) | (millions of dollars) | |
| **Development Projects:** | | | | | |
| Supply to Essex County Transmission Reinforcement | Windsor-Essex area Southwestern Ontario | New transmission line and station | 2018 | 56[1] | 54 |
| Clarington Transmission Station | Oshawa area Southwestern Ontario | New transmission station | 2018 | 240[1] | 238 |
| Niagara Reinforcement Project | Niagara area Southwestern Ontario | New transmission line | 2019 | 130 | 121 |
| East-West Tie Station Expansion | Northern Ontario | New transmission connection and station expansion | 2022 | 157 | 16 |
| Northwest Bulk Transmission Line Development | Thunder Bay-Atikokan Northwestern Ontario | New transmission line | 2024 | 35[2] | 1 |
| **Sustainment Projects:** | | | | | |
| Richview Transmission Station Circuit Breaker Replacement | Toronto Southwestern Ontario | Station sustainment | 2020 | 102 | 99 |
| Bruce A Transmission Station | Tiverton Southwestern Ontario | Station sustainment | 2020 | 138 | 123 |
| Beck #2 Transmission Station Circuit Breaker Replacement | Niagara area Southwestern Ontario | Station sustainment | 2022 | 113 | 65 |
| Lennox Transmission Station Circuit Breaker Replacement | Napanee Southeastern Ontario | Station sustainment | 2023 | 99 | 59 |

1 Major portions of the Supply to Essex County Transmission Reinforcement and Clarington Transmission Station projects were completed and placed in-service in 2018. Work on certain minor portions of the project continues in 2019.

2 The scope of the Northwest Bulk Transmission Line Development project, as specified by the IESO on October 24, 2018, is currently limited to the development phase only, reducing the estimated cost to $35 million.

## Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2019 to 2023. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework.

The 2019 transmission capital investments estimates differ from the prior year disclosures, representing a decrease to reflect Hydro One's recent one-year inflation-based application for 2019 transmission rates. The 2020 to 2022 transmission capital investments estimates are lower than the prior year disclosures as the Company has updated its plan for timing and pacing of future capital investments, as well as reprioritization of work. The projections and the timing of 2020-2023 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2019 to 2023, by business segment:

| (millions of dollars) | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Transmission | 1,049 | 1,203 | 1,329 | 1,380 | 1,381 |
| Distribution | 751 | 714 | 728 | 814 | 757 |
| Other | 13 | 15 | 26 | 9 | 10 |
| **Total capital investments** | **1,813** | **1,932** | **2,083** | **2,203** | **2,148** |

The following table summarizes Hydro One's annual projected capital investments for 2019 to 2023, by category:

| (millions of dollars) | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Sustainment | 1,148 | 1,211 | 1,467 | 1,574 | 1,530 |
| Development | 442 | 502 | 431 | 473 | 468 |
| Other[1] | 223 | 219 | 185 | 156 | 150 |
| **Total capital investments** | **1,813** | **1,932** | **2,083** | **2,203** | **2,148** |

1 "Other" capital expenditures consist of special projects, such as those relating to IT.

## SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Cash provided by operating activities | 1,575 | 1,716 |
| Cash provided by (used in) financing activities | 399 | (201) |
| Cash used in investing activities | (1,516) | (1,540) |
| **Increase (decrease) in cash and cash equivalents** | **458** | (25) |

### Cash provided by operating activities

The decrease of $141 million in cash from operating activities for the year ended December 31, 2018 compared to 2017 was impacted by various factors, including improved collection of accounts receivables in 2017 that reached a stabilized level in 2018, and disposition of certain regulatory variance and deferral accounts in 2018, partially offset by higher cash earnings in 2018.

### Cash provided by financing activities

**Sources of cash**

- The Company issued long-term debt of $1,400 million in 2018, compared to no long-term debt issued in 2017.
- The Company received proceeds of $4,242 million from the issuance of short-term notes in 2018, compared to $3,795 million received in 2017.
- In 2017, the Company received proceeds of $513 million, representing the first instalment of the convertible debentures issued, gross of $27 million financing costs, compared to no convertible debenture issuances in 2018.

**Uses of cash**

- The Company repaid $3,916 million of short-term notes in 2018, compared to $3,338 million repaid in 2017.
- The Company repaid $753 million of long-term debt in 2018, compared to long-term debt of $602 million repaid in 2017.
- Dividends paid in 2018 were $560 million, consisting of $542 million common share dividends and $18 million of preferred share dividends, compared to dividends of $536 million paid in 2017, consisting of $518 million common share dividends and $18 million of preferred share dividends.

### Cash used in investing activities

**Uses of cash**

- Capital expenditures and future use asset purchases were lower in 2018, primarily due to lower volume and timing of capital investment work.

## LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through FFO, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2018, Hydro One Inc. had $1,252 million in commercial paper borrowings outstanding, compared to $926 million outstanding at December 31, 2017. The interest rates on the commercial paper borrowings outstanding at December 31, 2018 ranged from 1.9% to 2.3%. In addition, the Company has revolving bank credit facilities (Operating Credit Facilities) with total availability of $2,550 million maturing in 2021 and 2022, with no amounts used at December 31, 2018 or 2017. The Company may use these credit facilities for working capital and general corporate purposes. On February 1, 2019, Hydro One entered into a credit agreement for a $170 million unsecured demand operating credit facility (Demand Facility) for the purpose of funding the payment of the termination fee payable to Avista Corporation as a result of the termination of the Merger Agreement and other Merger related costs. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, the Demand Facility and anticipated levels of FFO are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2018, the Company had long-term debt outstanding in the principal amount of $10,716 million which included $10,573 million of long-term debt issued by Hydro One Inc. and long-term debt in the principal amount of $143 million issued by HOSSM. The majority of long-term debt issued by Hydro One Inc. has been issued under its Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in March 2018 is $4.0 billion. At December 31, 2018, $2.6 billion remained available for issuance until April 2020. The long-term debt consists of notes and debentures that mature between 2019 and 2064, and at December 31, 2018, had a weighted-average term to maturity of approximately 16.3 years and a weighted-average coupon rate of 4.2%.

On June 18, 2018, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada to replace the universal base shelf prospectus that expired on April 30, 2018. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $4.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on July 18, 2020. On November 23, 2018, Hydro One Holdings Limited (HOHL), an indirect wholly-owned subsidiary of Hydro One, filed a short form base shelf prospectus (US Debt Shelf Prospectus) with securities regulatory authorities in Canada and the US for the purposes of, but not limited to, funding a portion of the cash purchase price of the Merger. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US$3.0 billion of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending on December 23, 2020. At December 31, 2018, no securities have been issued under the Universal Base Shelf Prospectus or the US Debt Shelf Prospectus.

### Acquisition Credit Facilities

For the purpose of bridge financing for the Merger, the Company secured a $1.0 billion non-revolving equity bridge credit facility, and a US$2.6 billion non-revolving debt bridge credit facility (Acquisition Credit Facilities) in June 2018. As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), on January 24, 2019, the Company cancelled the Acquisition Credit Facilities.

To mitigate the foreign currency risk related to the portion of the Merger purchase price financed by the issuance of convertible debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars. For the year ended December 31, 2018, an unrealized fair value gain of $25 million was recorded related to this contract, compared to an unrealized fair value loss of $3 million recorded for the year ended December 31, 2017. At December 31, 2018, the corresponding derivative asset was $22 million, compared to a derivative liability of $3 million at December 31, 2017. As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), no payment is due or receivable by Hydro One on the foreign exchange contract.

### Compliance

At December 31, 2018, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

### Credit Ratings

Various ratings organizations review the Company's and Hydro One Inc.'s debt ratings from time to time. These ratings organizations may take various actions, positive or negative. The Company cannot predict what actions rating agencies may take in the future. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and a downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt.

On June 20, 2018, Moody's Investors Service (Moody's) downgraded the long-term debt rating for Hydro One Inc. to "Baa1" from "A3", and revised its outlook on Hydro One Inc. to stable from negative. In addition, Moody's affirmed the existing "Prime-2" short-term debt rating for Hydro One Inc. Moody's no longer assigns any probability of extraordinary support from the Province of Ontario (Province) in Hydro One Inc.'s credit analysis which has led to the downgrade.

On June 15, 2018, S&P Global Ratings (S&P) placed its ratings on the Company and Hydro One Inc. on CreditWatch negative reflecting the likelihood of a one-notch downgrade to both companies due to the Merger. On July 18, 2018, S&P released an update maintaining the CreditWatch negative placement, which continued to reflect the likelihood of a one-notch downgrade in the Company and Hydro One Inc.'s issuer credit rating of "A" due to the Merger, and also incorporated the possibility that the Company's governance structure could result in an additional one-notch downgrade if S&P concludes that recent developments related to the retirement of the Company's Chief Executive Officer (CEO) and the replacement of the Company's Board of Directors (Board) adversely impact management decision making and fails to promote the interests of all stakeholders. See section "Hydro One Board of Directors and Executive Officers" for more information.

On September 13, 2018, S&P lowered its issuer credit ratings on the Company to "A-" from "A". At the same time, S&P lowered the issue-level rating on Hydro One Inc.'s senior unsecured debt by one notch to "A-" from "A" and lowered the rating on Hydro One Inc.'s commercial paper program by one notch to "A-1(low)" from "A-1(mid)" on the Canadian National Scale. All ratings remained on CreditWatch where S&P placed them with negative implications on June 15, 2018. The one-notch downgrade reflected S&P's reassessment of Hydro One's management and governance structure, which according to S&P has weakened following the Province's decision to exert its influence on the Company's compensation structure through legislation, potentially promoting the interests and priorities of one owner above those of other stakeholders.

On December 10, 2018, S&P removed Hydro One's ratings from CreditWatch with negative implications due to S&P's revised assumption that the Merger was unlikely to close as expected, following the Washington Utilities and Transportation Commission (Washington UTC) decision on December 5, 2018 to deny the Merger. Also on this date, S&P placed the issuer credit rating on Hydro One and the issue-level rating on Hydro One Inc.'s senior unsecured debt on negative outlook due to uncertainty about Hydro One's ability to convert its strategy into constructive actions that support the Company's financial performance, broader concerns related to Hydro One's governance, and uncertainty regarding the Company's strategic direction.

At December 31, 2018, Hydro One's corporate credit ratings were as follows:

| Rating Agency | Corporate Credit Rating |
|---|---|
| S&P | A- |

At December 31, 2018, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

| Rating Agency | Short-term Debt Rating | Long-term Debt Rating |
|---|---|---|
| DBRS Limited | R-1 (low) | A (high) |
| Moody's | Prime-2 | Baa1 |
| S&P | A-1 (low) | A- |

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

## Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated ROE is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. See section "Risk Management and Risk Factors – Risks Relating to Hydro One's Business – Market, Financial Instrument and Credit Risk" for more details.

## Pension Plan

In 2018, Hydro One contributed approximately $75 million to its pension plan, compared to contributions of approximately $87 million in 2017, and incurred $75 million in net periodic pension benefit costs, compared to $88 million incurred in 2017.

In April 2018, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2017. Based on this valuation and 2018 levels of pensionable earnings, the 2018 annual Company pension contributions of $75 million were comparable to $71 million as estimated at December 31, 2016. Hydro One estimates that total Company pension contributions for 2019, 2020, 2021, 2022, 2023 and 2024 are approximately $78 million, $77 million, $78 million, $79 million, $81 million and $83 million, respectively.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits".

## OTHER OBLIGATIONS

### Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

### Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

| December 31, 2018 (millions of dollars) | Total | Less than 1 year | 1-3 years | 3-5 years | More than 5 years |
|---|---|---|---|---|---|
| **Contractual obligations** (due by year) | | | | | |
| Long-term debt – principal repayments | 10,716 | 731 | 1,456 | 734 | 7,795 |
| Long-term debt – interest payments | 8,181 | 448 | 840 | 772 | 6,121 |
| Convertible debentures – principal repayments[1] | 513 | — | — | — | 513 |
| Convertible debentures – interest payments[1] | 539 | 62 | 123 | 123 | 231 |
| Short-term notes payable | 1,252 | 1,252 | — | — | — |
| Pension contributions[2] | 476 | 78 | 155 | 160 | 83 |
| Environmental and asset retirement obligations | 186 | 26 | 61 | 59 | 40 |
| Outsourcing and other agreements | 310 | 161 | 133 | 5 | 11 |
| Operating lease commitments | 28 | 7 | 15 | 2 | 4 |
| Long-term software/meter agreement | 39 | 17 | 18 | 3 | 1 |
| **Total contractual obligations** | 22,240 | 2,782 | 2,801 | 1,858 | 14,799 |
| **Other commercial commitments** (by year of expiry) | | | | | |
| Operating Credit Facilities | 2,550 | — | 250 | 2,300 | — |
| Letters of credit[3] | 182 | 182 | — | — | — |
| Guarantees[4] | 325 | 325 | — | — | — |
| **Total other commercial commitments** | 3,057 | 507 | 250 | 2,300 | — |

1 As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), on February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts $513 million plus accrued and unpaid interest of $7 million.

2 Contributions to the Hydro One Pension Fund are generally made one month in arrears. Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable.

3 Letters of credit consist of a $163 million letter of credit related to retirement compensation arrangements, a $13 million letter of credit provided to the IESO for prudential support, $5 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

4 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

## SHARE CAPITAL

The common shares of Hydro One are publicly traded on the Toronto Stock Exchange (TSX) under the trading symbol "H". Hydro One is authorized to issue an unlimited number of common shares. The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board may consider relevant. At February 20, 2019, Hydro One had 595,940,880 issued and outstanding common shares.

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At February 20, 2019, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At February 20, 2019, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

The number of additional common shares of Hydro One that would be issued if all outstanding awards under the share grant plans and the Long-term Incentive Plan (LTIP) were vested and exercised as at February 20, 2019 is 6,231,715.

## REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings with the OEB:

| Application | Years | Type | Status |
|---|---|---|---|
| **Electricity Rates** | | | |
| Hydro One Networks | 2017-2018 | Transmission – Cost-of-service | OEB decision received[1] |
| Hydro One Networks | 2019 | Transmission – Revenue Cap | OEB decision pending |
| Hydro One Networks | 2018-2022 | Distribution – Custom | OEB decision received |
| B2M LP | 2015-2019 | Transmission – Cost-of-service | OEB decision received |
| HOSSM | 2017-2026 | Transmission – Revenue Cap | OEB decision received[2] |
| **Mergers Acquisitions Amalgamations and Divestitures (MAAD)** | | | |
| Orillia Power | n/a | Acquisition | OEB decision pending[3] |
| Peterborough Distribution | n/a | Acquisition | OEB decision pending |
| **Leave to Construct** | | | |
| East-West Tie Station Expansion | n/a | Section 92 | OEB decision received |
| Lake Superior Link Project | n/a | Section 92 | OEB decision received[4] |

1 On March 7, 2019, the OEB upheld its Original Decision relating to the deferred tax asset. The Company is currently considering its options under the Appeal.

2 In October 2016, the OEB approved the 2017-2026 revenue requirements. In July 2018, HOSSM filed an application for an inflationary increase (Revenue Cap Escalator factor) to its 2019 revenue requirement.

3 In September 2018, Hydro One filed a new MAAD application with the OEB to acquire Orillia Power.

4 On February 11, 2019, the OEB issued its decision awarding the construction of the East-West Tie Line to NextBridge, as directed by the Province on January 30, 2019.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

| Application | Year | ROE Allowed (A) or Forecast (F) | Rate Base Allowed (A) or Forecast (F) | Rate Application Status | Rate Order Status |
|---|---|---|---|---|---|
| **Transmission** | | | | | |
| Hydro One Networks | 2018 | 9.00% (A) | $11,148 million (A) | Approved in September 2017 | Approved in December 2017 |
| | 2019 | n/a[1] | n/a[1] | Filed in October 2018 | To be filed |
| B2M LP | 2018 | 9.00% (A) | $502 million (A) | Approved in December 2015 | OEB decision received |
| | 2019 | 8.98% (A) | $496 million (A) | Approved in December 2015 | Approved in December 2018 |
| HOSSM | 2017-2026 | 9.19% (A) | $218 million (A) | Approved in October 2016 | OEB decision received[2] |
| **Distribution** | | | | | |
| Hydro One Networks | 2018 | 9.00% (A) | $7,650 million (F) | Filed in March 2017[3] | To be filed in 2019 Q1 |
| | 2019 | 8.98% (A) | $8,009 million (F) | Filed in March 2017[3] | To be filed in 2019 Q1 |
| | 2020 | 8.98% (F) | $8,412 million (F) | Filed in March 2017[3] | To be filed in 2019 Q4 |
| | 2021 | 8.98% (F) | $8,941 million (F) | Filed in March 2017[3] | To be filed in 2020 Q4 |
| | 2022 | 8.98% (F) | $9,306 million (F) | Filed in March 2017[3] | To be filed in 2021 Q4 |

1 The Revenue Cap application is a formulaic adjustment to the approved revenue requirement and does not consider ROE or rate base.

2 In October 2016, the OEB approved the 2017-2026 revenue requirements. In July 2018, HOSSM filed an application for an inflationary increase (Revenue Cap Escalator factor) to its 2019 revenue requirement.

3 In June 2018, Hydro One Networks filed an undertaking with the OEB which included updated rate base amounts.

## Electricity Rates Applications

### Hydro One Networks – Transmission

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, reductions in OM&A expenses related to compensation by $15 million for each year, and reductions in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Original Decision.

In its Original Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a decision and order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, on March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result of this subsequent event that requires adjustment in the 2018 financial statements, the Company has recognized an impairment charge of Hydro One Networks' distribution deferred income tax regulatory asset of $474 million and Hydro One Networks' transmission deferred income tax regulatory asset of $558 million, an increase in deferred income tax regulatory liability of $81 million, and a decrease in the forgone revenue deferral regulatory asset of $68 million. After recognition of the related $314 million deferred tax asset, the Company has recorded an $867 million one-time decrease in net income as a reversal of revenues of $68 million, and charge to deferred tax expense of $799 million, which is expected to result in an annual decrease to FFO in the range of $50 million to $60 million. Notwithstanding the recognition of the effects of the decision in the financial statements, the Company is currently considering its options under the Appeal.

See section "Risk Management and Risk Factors - Risks Relating to Hydro One's Business - Risks Relating to Regulatory Treatment of Deferred Tax Asset" for description of related risks.

On November 23, 2017, the OEB approved the 2017 transmission revenue requirement of $1,438 million. In December 2017, the OEB approved the 2018 transmission revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

On November 23, 2017, the OEB approved the 2017 transmission revenue requirement of $1,438 million. In December 2017, the OEB approved the 2018 transmission revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

On March 16, 2018, the OEB issued a letter requesting Hydro One to file the transmission revenue requirement application for a four-year test period from 2019 to 2022, rather than the minimum 5-year period allowed under existing OEB policy. The OEB indicated that it is more appropriate to consider rates for Hydro One's distribution and transmission businesses in a single application, and stated that it expected Hydro One to file a single application for distribution rates (including Hydro One Remote Communities) and transmission revenue requirement for the period from 2023 to 2027.

A one-year inflation-based application for 2019 transmission rates was filed with the OEB on October 26, 2018. On December 20, 2018, the OEB issued a decision declaring Hydro One's revenue requirement and the UTRs for 2019 as interim.

### Hydro One Networks – Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels.

The OEB oral hearing related to Hydro One Networks' application for 2018-2022 distribution rates was held on June 11-28, 2018. On August 31, 2018, Hydro One submitted its final argument. Subsequently, steps were taken to address the outstanding issues related to pole attachment fees and matters relating to recovery of certain amounts paid for executive compensation, as per the *Hydro One Accountability Act* (Accountability Act). See section "Hydro One Board of Directors and Executive Officers" for more information. On December 6, 2018, Hydro One made its final submission on matters relating to the Accountability Act and the impact on revenue requirement. Regarding the pole attachment fees, after following the process outlined by the OEB, Hydro One proposed the use of the province-wide pole attachment rate, effective January 1, 2019. On November 15, 2018, the OEB accepted the proposal. On March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates. See above in "Hydro One Networks – Transmission" for impacts relating to the distribution deferred income tax regulatory asset.

On June 27, 2018, the OEB issued a letter deferring Hydro One's request for the OEB to approve an alternative method to calculate amounts related to the post-employment benefit costs for Hydro One Networks' distribution business until the next re-basing application is filed, as the OEB noted that the issue is relevant to both the distribution and transmission businesses of Hydro One Networks. In the 2019 transmission rates application filed with the OEB on October 26, 2018, Hydro One requested this decision be made as part of its next transmission re-basing application.

**B2M LP**

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017, 2018 and 2019 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On May 10, 2018, the OEB issued its Decision and Rate Order on B2M LP's 2018 transmission application reflecting revenue requirement of $36 million, effective January 1, 2018.

On November 23, 2018, a revised 2019 revenue requirement using the updated cost of capital parameters was filed with the OEB. On December 20, 2018, the OEB issued its Decision on UTRs effective January 1, 2019, approving the requested 2019 revenue requirement of $33 million.

**HOSSM**

HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB MAAD decision dated October 13, 2016. On July 26, 2018, HOSSM filed a 2019 application to allow for inflationary increase (Revenue Cap Escalator factor) to its previously approved revenue requirement. The Revenue Cap Escalator factor is designed to add inflationary increases to the revenue requirement on an annual basis. The proceeding continues and an OEB decision is expected in the second quarter of 2019.

**Hydro One Remote Communities**

On August 28, 2017, Hydro One Remote Communities filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On March 19, 2018, the OEB approved the settlement agreement related to the 2018 rates application reached by Hydro One Remote Communities and the intervenors in the rate proceeding. On March 26, 2018, a draft rate order was filed with the OEB for 2018 rates. The OEB approved the draft rate order on April 12, 2018, and the new rates were implemented effective May 1, 2018.

On November 5, 2018, Hydro One Remote Communities filed an application with the OEB seeking approval for increased base rates of 1.8% effective May 1, 2019. On February 11, 2019, the OEB issued a draft decision approving the requested increase.

Hydro One Remote Communities is fully financed by debt and is operated as a break-even entity with no ROE.

**Niagara Reinforcement Limited Partnership (NRLP)**

On September 19, 2018, NRLP was formed to own and operate a new 230 kV transmission line in the Niagara region that will enable generators in the Niagara area to connect to the load centres of the Greater Toronto and Hamilton areas. NRLP is designed to include minority participation of local First Nations partners in a structure similar to B2M LP.

On September 27, 2018, Hydro One filed a transmission licence application with the OEB for NRLP. On October 25, 2018, Hydro One filed two other applications with the OEB relating to NRLP requesting approval for Hydro One Networks to sell the applicable assets to NRLP and approval of interim rates to include in the 2019 UTRs. On December 20, 2018, the OEB issued a decision finding that the request for approval for an interim revenue requirement effective January 1, 2019 was premature but indicated that there would be an opportunity to adjudicate the matter at a later date. NRLP expects the OEB to decide on this application later in 2019.

## MAAD Applications

**Orillia Power MAAD Application**

In 2016, Hydro One filed a MAAD application (2016 Application) with the OEB to acquire Orillia Power Distribution Corporation (Orillia Power) from the City of Orillia, Ontario. On April 12, 2018, the OEB issued a decision denying Hydro One's proposed acquisition of Orillia Power. The decision indicated that with the exception to pricing, the transaction met the no harm test. Additionally, the OEB indicated that it required additional evidence on the overall cost structure following the deferral period and the impact on Orillia Power's customers. On May 2, 2018, Hydro One and Orillia Power both filed a Motion to Review and Vary the OEB's decision, and on August 23, 2018, the OEB issued a decision upholding its April 12, 2018 decision to deny Hydro One's proposed acquisition of Orillia Power.

On September 26, 2018, Hydro One filed a new MAAD application (2018 Application) with the OEB to acquire Orillia Power. The evidence in the 2018 Application is similar to that provided in the 2016 Application. However it includes additional information that was not available at the time Hydro One filed its 2016 MAAD Application, including updates to reflect current variables to costs and other metrics, as well as future cost structures pertaining to the acquired entity.

On October 16, 2018, the School Energy Coalition (SEC) filed a motion with the OEB seeking an order dismissing the 2018 Application. On January 16, 2019, Hydro One and Orillia Power filed submissions on the SEC motion, maintaining that the motion should be dismissed, and the 2018 Application should be heard by the OEB. A decision by the OEB is pending.

**Peterborough Distribution MAAD Application**

On October 12, 2018, the Company filed an application with the OEB for approval of the acquisition of business and distribution assets of Peterborough Distribution Inc. (Peterborough Distribution). On October 25, 2018, an advance ruling certification application was filed with the Competition Bureau. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's perspective. The decision of the OEB is still pending. See section "Other Developments – Peterborough Distribution Purchase Agreement" for more information on the acquisition.

## Other Applications

**East-West Tie / Lake Superior Link**

On February 15, 2018, Hydro One filed a Leave to Construct application with the OEB to construct a transmission line (East-West Tie Line) in northwestern Ontario (Lake Superior Link Project), which competed with an application filed by NextBridge to construct the East-West Tie Line. Pursuant to the OEB's direction, on July 26, 2018, the IESO issued its analysis of the impacts of a delay to the in-service date for the construction of the East-West Tie Line. In its analysis, the IESO recommends an in-service date of 2020 for the completion of the East-West Tie Line and does not support a delay beyond 2022, due to increased risks to system reliability and the associated cost uncertainties.

A combined OEB oral hearing for the Hydro One Lake Superior Link Project application, the Hydro One East-West Tie Station Expansion application, and the NextBridge East-West Tie Line application was held in October 2018. On December 20, 2018, the OEB approved Hydro One's East-West Tie Station Expansion application. However, with respect to approval for the Lake Superior Link Project, the OEB decided to add a further step requesting both Hydro One and NextBridge to submit a final not-to-exceed price by January 31, 2019, noting that price will be the deciding factor.

On January 18, 2019, BLP First Nations (BLP) filed a Notice of Appeal to Divisional Court appealing the OEB's December decision, asserting that the OEB decision lacks consideration and application of duty to consult in section 35 of the *Constitution Act, 1982*. On the same date, NextBridge filed a Notice of Appeal to Divisional Court appealing portions of the OEB's December decision that relate to transferring information attained in the environmental assessment process to Hydro One and the disallowance of recovery of a portion of NextBridge's development work. On January 30, 2019, the Minister of Energy, Northern Development and Mines, issued a directive to the OEB to amend NextBridge's electricity transmission licence and allow it to proceed with the East-West Tie transmission line, effectively ending Hydro One's competitive bid to build the Lake Superior Link Project. On February 11, 2019, the OEB issued its decision awarding the construction of the East-West Tie Line to NextBridge. As a result, in the first quarter of 2019, Hydro One recognized an impairment loss of approximately $11 million associated with previously capitalized costs related to this project.

## OTHER DEVELOPMENTS

### Exemptive Relief

#### Disclosure of Ownership by the Province

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (OPG) (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

#### US GAAP

On March 27, 2018, Hydro One was granted exemptive relief by securities regulators in each province and territory of Canada which allows Hydro One to continue to report its financial results in accordance with US GAAP (Exemptive Relief). The Exemptive Relief will remain in effect until the earlier of: (i) January 1, 2024; (ii) the first day of Hydro One's financial year that commences after Hydro One ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation.

### Litigation

#### Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal.

#### Litigation Relating to the Merger

To date, four putative class action lawsuits were filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in *Fink* has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants.

### Peterborough Distribution Purchase Agreement

On July 31, 2018, Hydro One reached an agreement to acquire the business and distribution assets of Peterborough Distribution, an electricity distribution company located in east central Ontario, from the City of Peterborough. Hydro One will pay the City of Peterborough $105 million for the transaction. The acquisition is conditional upon the satisfaction of customary closing conditions and approval by the OEB and the Competition Bureau. On October 12, 2018, the Company filed an application with the OEB for approval of the acquisition. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's perspective. The decision of the OEB is still pending.

### Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation. The completion of the Merger was subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Regulatory Commission of Alaska, the Washington UTC, the Idaho Public Utilities Commission (Idaho PUC), Oregon Public Utility Commission (Oregon PUC), the Public Service Commission of the State of Montana, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission, and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement.

Following the announcement on July 11, 2018 of the resignation of Hydro One's Board and the immediate retirement of its President and CEO (see section "Hydro One Board of Directors and Executive Officers" for more information), regulatory authorities in Washington and Oregon extended the timetable for arriving at a decision in Hydro One's proposed acquisition of Avista Corporation to mid-December 2018. In addition, the Idaho PUC rescheduled its hearing from July 23, 2018 to November 26-27, 2018. The Idaho PUC denied approval of the merger on January 3, 2019. The Washington UTC denied approval of the merger on December 5, 2018. On December 17, 2018, Hydro One and Avista Corporation filed a petition for reconsideration and a petition for a rehearing with the Washington UTC. On January 8, 2019, the Washington UTC gave notice of the deemed denial by operation of law (effective January 7, 2019) of the petition for reconsideration filed by Hydro One and Avista Corporation. In the same notice, the Washington UTC also denied the petition for a rehearing on the basis that it is moot because of the deemed denial of the petition for reconsideration.  In light of the decisions by the Washington UTC and the Idaho PUC to deny approval of the Merger, the Oregon PUC issued an order on January 14, 2019 suspending indefinitely the current procedural schedule in its Merger docket until Hydro One and Avista Corporation inform the Oregon PUC that they have sought a reversal of the denial decisions through appeal or other means that would provide a justiciable issue for the Oregon PUC to address.

On January 23, 2019, Hydro One and Avista Corporation announced that the companies have mutually agreed to terminate the Merger agreement. As a result of the termination of the Merger agreement, on January 24, 2019, Hydro One paid a US$103 million termination fee to Avista Corporation as required by the Merger agreement. On January 24, 2019, the Company cancelled the Acquisition Credit Facilities, with no amounts drawn. On February 1, 2019, Hydro One entered into the Demand Facility for the purpose of funding the payment of the termination fee and other Merger related costs. On February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts $513 million ($333 per $1,000 principal amount) plus accrued and unpaid interest of $7 million. The redemption of the convertible debentures was paid with cash on hand. As a result of the termination of the Merger agreement, no payment is due or receivable by Hydro One on the foreign exchange contract.

The following amounts related to the termination of the Merger agreement will be recorded by the Company in its 2019 first quarter financial statements:

- approximately $138 million OM&A costs for payment of the US$103 million termination fee;
- $22 million financing charges, due to revaluation of the foreign-exchange contract to $nil and reversal of previously recorded gains;
- repayment of $513 million convertible debentures and related interest of $7 million; and
- $24 million financing charges, due to derecognition of the deferred financing costs related to convertible debentures.

## HYDRO ONE BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

### Directors and Executive Officers

On July 11, 2018, Hydro One, on behalf of itself and its wholly-owned subsidiary, Hydro One Inc., announced that it had entered into an agreement (Letter Agreement) with the Province for the purpose of the orderly replacement of the Board of Hydro One and Hydro One Inc. and the retirement of Mayo Schmidt as the CEO effective July 11, 2018. Hydro One also announced the appointment of Paul Dobson as Acting President and CEO of Hydro One and Hydro One Inc. effective July 11, 2018.

On August 14, 2018, Hydro One announced a new Board. Six directors were identified and nominated by an ad hoc nominating committee, comprised of three of the five largest shareholders of Hydro One excluding the Province, and four directors were identified and nominated by the Province, Hydro One's largest shareholder. Each of the directors is independent of both Hydro One and the Province in accordance with the Governance Agreement dated as of November 5, 2015 between Hydro One and the Province (Governance Agreement).

The directors of Hydro One and Hydro One Inc. are the same in accordance with the provisions of the Governance Agreement.

On September 7, 2018, Hydro One announced the appointment of Chris Lopez as Acting Chief Financial Officer (CFO) of Hydro One and Hydro One Inc., effective September 6, 2018. On September 7, 2018, Hydro One announced the appointment of Tom Woods as Chair of the Board of Hydro One and Hydro One Inc., effective September 6, 2018. Patrick Meneley, Executive Vice President and Chief Corporate Development Officer has advised the Company of his decision to leave Hydro One effective March 1, 2019.

The following table sets forth information regarding the current directors and executive officers of Hydro One and Hydro One Inc. as at December 31, 2018. Each of the directors was first appointed effective August 14, 2018. Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

| Name, Province or State and Country of Residence | Age | Position/Title | Independent Board Member | Principal Occupation | Committees |
|---|---|---|---|---|---|
| Paul Dobson<br>Texas, USA | 52 | Acting President and CEO | | Acting President and CEO | |
| Jason Fitzsimmons<br>Ontario, Canada | 48 | Chief Corporate Affairs and Customer Care Officer | | Chief Corporate Affairs and Customer Care Officer | |
| Gregory Kiraly<br>Arizona, USA | 54 | Chief Operating Officer | | Chief Operating Officer | |
| Chris Lopez<br>Alberta, Canada | 44 | Acting CFO | | Acting CFO | |
| Judy McKellar<br>Ontario, Canada | 62 | Executive Vice President, Chief Human Resources Officer | | Executive Vice President, Chief Human Resources Officer | |
| Patrick Meneley<br>Ontario, Canada | 55 | Executive Vice President and Chief Corporate Development Officer | | Executive Vice President and Chief Corporate Development Officer | |
| James Scarlett<br>Ontario, Canada | 65 | Executive Vice President and Chief Legal Officer | | Executive Vice President and Chief Legal Officer | |
| Tom Woods[1]<br>Ontario, Canada | 66 | Director and Chair of the Board | Yes | Director | |
| Cherie Brant[1]<br>Ontario, Canada | 44 | Director | Yes | Partner, Dickinson Wright LLP | Governance Committee; Health, Safety, Environment and Indigenous Peoples Committee |
| Blair Cowper-Smith[1]<br>Ontario, Canada | 70 | Director | Yes | Director | Governance Committee (Chair); Human Resources Committee |
| Anne Giardini<br>British Columbia, Canada | 59 | Director | Yes | Director | Audit Committee; Health, Safety, Environment and Indigenous Peoples Committee (Chair) |
| David Hay<br>New Brunswick, Canada | 63 | Director | Yes | Managing Partner, Delgatie Incorporated | Audit Committee; Health, Safety, Environment and Indigenous Peoples Committee |
| Timothy Hodgson<br>Ontario, Canada | 58 | Director | Yes | Managing Partner and Director, Alignvest Management Corporation | Governance Committee; Human Resources Committee |
| Jessica McDonald<br>British Columbia, Canada | 49 | Director | Yes | Interim President and CEO, Canada Post Corporation | Audit Committee; Human Resources Committee |
| Russel Robertson[1]<br>Ontario, Canada | 71 | Director | Yes | Director | Audit Committee; Human Resources Committee |
| William Sheffield<br>Ontario, Canada | 70 | Director | Yes | Director | Audit Committee (Chair); Health, Safety, Environment and Indigenous Peoples Committee |
| Melissa Sonberg<br>Québec, Canada | 58 | Director | Yes | Adjunct Professor, McGill University | Governance Committee; Human Resources Committee (Chair) |

1 These directors have been designated as the Province's nominees to the Board of Hydro One for the purpose of the Governance Agreement.

The following includes a brief profile of each of the executive officers and directors of Hydro One and Hydro One Inc., which includes a description of their present occupation and their principal occupations for the past five years:

**Paul Dobson – Acting President and CEO**
Effective July 11, 2018, Paul Dobson was appointed to the role of Acting President and CEO of Hydro One. Mr. Dobson joined the Company as CFO on March 1, 2018 responsible for finance, treasury, controller, internal audit, technology and regulation. Prior to joining Hydro One in 2018, Mr. Dobson served as CFO for Direct Energy Ltd. (Direct Energy), Houston, Texas, where he was responsible for overall financial leadership of a $15 billion revenue business with three million customers in Canada and the US. Since 2003, Mr. Dobson has held senior leadership positions in finance, operations, IT and customer service across the Centrica Group, the parent company of Direct Energy. Prior to Direct Energy, Mr. Dobson worked at CIBC for 10 years in finance, strategy and business development roles in both Canada and the US. Mr. Dobson also brings considerable experience in mergers and acquisitions and integrating acquired companies across North America and in the United Kingdom. Mr. Dobson is a dual Canadian-US citizen who holds an honours bachelor's degree from the University of Waterloo as well as a Masters of Business Administration (MBA) from the University of Western Ontario and is a CPA, CMA.

**Jason Fitzsimmons – Chief Corporate Affairs and Customer Care Officer**
Jason Fitzsimmons was promoted to Chief Corporate Affairs and Customer Care Officer in August 2018, with oversight of the customer service, corporate affairs, marketing and Indigenous relations functions. With more than 25 years of experience in the electricity sector, Mr. Fitzsimmons is a highly-regarded leader with a proven track record for successfully executing large-scale transformations and building strong relationships with key stakeholders. In his previous role as Vice President, Labour Relations at Hydro One, Mr. Fitzsimmons played an instrumental role in bringing the company's 400-employee Customer Contact Centre in-house as the Company continuously strives to deliver best-in-class customer service. Prior to joining the Company in 2016, Mr. Fitzsimmons was the Chief Negotiations Officer at the Ontario Hospital Association and also held a number of executive roles at OPG, including Vice President of Human Resources for the Nuclear division. He is a Certified Human Resource Executive known for his broad experience in labour management as well as his passion for health and safety in the workplace. He was a prior member of the Advisory Board for Ryerson University's Centre for Labour Management Relations and has served on the Board for the Electrical Power Sector Construction Association.

**Gregory Kiraly – Chief Operating Officer**
Effective September 12, 2016, Gregory Kiraly was appointed to the role of Chief Operating Officer (COO) of Hydro One. As COO, Mr. Kiraly oversees the complete transmission and distribution value chain including planning, engineering, construction, operations, maintenance, and forestry; shared services functions including facilities, real estate, fleet, and procurement; and the Hydro One Telecom and Hydro One Remote Communities subsidiaries. Prior to joining Hydro One in 2016, Mr. Kiraly served as Senior Vice President of Electric Transmission and Distribution at Pacific Gas and Electric Company (PG&E) in San Francisco, which delivers safe and reliable energy to more than 16 million customers in northern and central California. Since joining PG&E in 2008, Mr. Kiraly led efforts that achieved the lowest employee injury rates ever, seven straight years of record electric reliability, and over $500 million in productivity improvements and efficiency savings. Before PG&E, Mr. Kiraly held executive-level positions in energy delivery at Commonwealth Edison (Exelon) in Chicago and leadership positions in both gas and electric distribution at Public Service Electric and Gas Company in Newark, New Jersey. Mr. Kiraly holds a bachelor's degree in industrial engineering from New Jersey Institute of Technology and an MBA in finance from Seton Hall University. He is also a graduate of Harvard University's Advanced Management Program.

**Chris Lopez – Acting CFO**
Effective September 6, 2018, Chris Lopez was appointed as Acting CFO for Hydro One. As Acting CFO, Mr. Lopez is responsible for corporate finance (including treasury and tax), internal audit, investor relations, and pensions. Mr. Lopez joined Hydro One on November 14, 2016 when he was appointed as Senior Vice President of Finance, bringing almost 17 years of progressive experience in the utilities industry in Canada and Australia. Prior to joining Hydro One, Mr. Lopez was the Vice President, Corporate Planning and Mergers & Acquisitions at TransAlta Corporation from 2011 to 2015. Prior to that, Mr. Lopez was Director of Operations Finance at TransAlta in Calgary from 2007 to 2011, and he held senior financial roles up to and including Country Financial Controller for TransAlta in Australia, from 1999 to 2007. Mr. Lopez worked as a Senior Financial Accountant with Rio Tinto Iron Ore, in Australia from 1997 to 1999. Mr. Lopez received a Bachelor of Business degree from Edith Cowan University in 1996, and a Chartered Accountant designation in Australia in 1999. He received a graduate diploma in corporate governance and directorships from the Australian Institute of Company Directors in 2007.

**Judy McKellar – Executive Vice President, Chief Human Resources Officer**
Judy McKellar is the Executive Vice President, Chief Human Resources Officer of Hydro One. She was appointed to this position on November 11, 2016. Ms. McKellar has held various roles of increasing responsibility at Hydro One Networks, an indirect subsidiary of Hydro One, in the Human Resources department over her 30+ year career and was appointed Vice President of Human Resources in 2010. In 2014, she assumed the additional responsibility of Senior Vice President of People and Culture/Health, Safety and Environment and serves as the accountable executive for the Human Resources Committee of the Board. Ms. McKellar earned a Bachelor of Arts degree from Victoria College, University of Toronto, and was recently named as one of 2015's 100 Most Powerful Women in Canada by PricewaterhouseCoopers in the "Public Sector" category.

**Patrick Meneley – Executive Vice President and Chief Corporate Development Officer**
Effective March 1, 2018, Patrick Meneley was appointed to the role of Executive Vice President and Chief Corporate Development Officer of Hydro One. In this capacity, Mr. Meneley is responsible for leading strategy, innovation and mergers and acquisitions. Prior to joining Hydro One in 2018, Mr. Meneley served as Executive Vice President, Wholesale Banking at TD Bank Group and Vice Chair and Head of Global Corporate and Investment Banking for TD Securities. Mr. Meneley spent 15 years leading and building one of the leading corporate and investment banking businesses in Canada, along with a profitable and growing franchise in the US. Mr. Meneley holds an MBA (with distinction) from the University of Western Ontario and a Bachelor of Commerce (with honours) from the University of British Columbia.

**James Scarlett – Executive Vice President and Chief Legal Officer**
Effective September 1, 2016, James Scarlett was appointed as Executive Vice President and Chief Legal Officer of Hydro One. Prior to joining Hydro One, Mr. Scarlett was a Senior Partner at Torys LLP. He joined Torys LLP in March 2000 and held a number of leadership roles at the firm, including head of Torys LLP's Capital Markets Group, Mining Group and International Business Development Strategy. Mr. Scarlett was also a member of the firm's Executive Committee from 2009-2015. Prior to joining Torys LLP, Mr. Scarlett was a Partner at another major Canadian law firm. While at that firm Mr. Scarlett held leadership roles as head of its Corporate Group, Securities Group and as a member of its Board. Mr. Scarlett was also seconded to the Ontario Securities Commission in 1987 and was appointed as the first Director of Capital Markets in 1988, a position he held until his return to private law practice in 1990. Mr. Scarlett earned his law degree (J.D.) from the University of Toronto in 1981 and his Bachelor of Commerce Degree from the University of McGill in 1975. Mr. Scarlett also holds his ICD.D.

**Thomas D. Woods (provincial nominee) – Board Chair**
Public Directorships (other than Hydro One and Hydro One Inc.): Bank of America Corporation

Public Board Interlocks: None

Mr. Woods is a corporate director. He previously had a 37-year career with CIBC and Wood Gundy, the predecessor firm of CIBC World Markets. He started in Investment Banking, advising companies raising financing in the equity and debt capital markets as well as mergers and acquisitions, and later was Head of Canadian Corporate Banking, Chief Financial Officer, Chief Risk Officer and served as Vice Chairman until his retirement in 2014.

Mr. Woods has served on the boards of Bank of America Corporation since 2016, Alberta Investment Management Corporation. Mr. Woods has also acted as Board Chair of Providence St. Joseph's St. Michael's Health Care since 2017 and CIBC Children's Foundation. Previous directorships include TMX Group Inc., DBRS Limited, Jarislowsky Fraser Limited and Covenant House (Board Chair). Mr. Woods has a Bachelor of Applied Science in Industrial Engineering from University of Toronto, and an MBA from Harvard Business School.

**Cherie L. Brant (provincial nominee)**
Public Directorships (other than Hydro One and Hydro One Inc.): None

Public Board Interlocks: None

Ms. Brant has been a Partner at Dickinson Wright's Toronto law office since 2013 where she has an Indigenous law practice with a focus on commercial real estate, energy and transmission and First Nations economic development. Ms. Brant provides strategic counsel to several First Nations and industry clients seeking to develop projects with First Nations and to understand and address Indigenous rights and interests. As lead counsel, Ms. Brant was instrumental in forming one of the largest First Nations-led limited partnerships in Canada resulting in the Ontario First Nations Sovereign Wealth LP's share purchase of approximately 2.4% of Hydro One Limited.

Ms. Brant is both Mohawk and Ojibway from the Mohawks of the Bay of Quinte and Wikwemikong Unceded Indian Territory. She also serves on the board of the Anishnawbe Health Foundation and is a member of the Canadian Council for Aboriginal Business, Research Advisory Board and the Aboriginal Energy Working Group of the Independent Electricity System Operator. Previous directorships include Women's College Hospital and Trillium Gift of Life.

Ms. Brant has a Bachelor of Environmental Studies, Urban and Regional Planning Program from the University of Waterloo and a Juris Doctor from the University of Toronto. She is a member of the Ontario Bar Association and the Law Society of Ontario.

**Blair Cowper-Smith (provincial nominee)**
Public Directorships (other than Hydro One and Hydro One Inc.): None

Public Board Interlocks: None

Mr. Cowper-Smith is the principal and founder of Erin Park Business Solutions, a Canadian advisory and consulting firm. Previously, he was Chief Corporate Affairs Officer of Ontario Municipal Employees Retirement System (OMERS) and served as a member of the Senior Executive Team from 2008 to 2017 where his responsibilities included regulatory affairs, law and governance. Prior to joining OMERS he was a Senior Partner at McCarthy Tetrault LLP where his practice focused on mergers and acquisitions, infrastructure, governance and private equity.

Mr. Cowper-Smith's Board experience includes numerous advisory assignments, including governance advisory assignments, with boards of directors including OMERS, Stelco, Hammerson, and includes existing or prior director appointments and board committee leadership roles with companies like Porter Airlines, 407 ETR, the Financial Services Regulatory Authority and Face the Future Foundation. He served until recently on the Public Policy Committee of the Canadian Coalition for Good Governance and on the Securities Advisory Committee of the Ontario Securities Commission. He co-founded The Canadian Council for Public and Private Partnerships which led to a long-term interest in infrastructure policy and delivery of infrastructure based services to Canadians.

Mr. Cowper-Smith has a Bachelor of Laws (LLB) and Master of Laws (LLM) from Osgoode Hall Law School at York University and holds his ICD.D. He is a member of the Law Society of Ontario.

**Anne Giardini, O.C., O.B.C., Q.C.**
Public Directorships (other than Hydro One and Hydro One Inc.):
Nevsun Resources Ltd.

Public Board Interlocks: None

Ms. Giardini has been a corporate director since 2014 and Chancellor of Simon Fraser University. She previously had a 20-year career with Weyerhaeuser Company Limited, including as Canadian President until her retirement in 2014. Before her tenure as President, she was Vice President and General Counsel at Weyerhaeuser where she worked on corporate, legal, policy and strategic matters. Ms. Giardini has been a newspaper columnist and is the author of two novels.

Ms. Giardini also serves on the boards of Nevsun Resources Ltd., Canada Mortgage & Housing Corporation, World Wildlife Fund (Canada), BC Achievement Foundation, TransLink and the Greater Vancouver Board of Trade. Previous directorships include Thompson Creek Metals Company, Inc. and Weyerhaeuser Company Limited.

Ms. Giardini has a BA in Economics from Simon Fraser University, a Bachelor of Laws from the University of British Columbia and a Master of Law from the University of Cambridge (Trinity Hall). She is licensed to practice law in British Columbia where she is a member of the Law Society of British Columbia (and formerly in Ontario and Washington State). In 2016, Ms. Giardini was appointed an Officer of the Order of Canada and in 2018 she was appointed to the Order of British Columbia.

**David Hay**
Public Directorships (other than Hydro One and Hydro One Inc.):
EPCOR Utilities Inc.

Public Board Interlocks: None

Mr. Hay is a corporate director and Managing Director of Delgatie Incorporated (2015). He is the former Vice-Chair and Managing Director of CIBC World Markets Inc. with power, utilities and infrastructure as his major focus (2010 to 2015). From 2004 until 2010, he was President and Chief Executive Officer of New Brunswick Power Corporation and held senior investment banking roles, including Senior Vice-President and Director responsible for mergers and acquisitions with Merrill Lynch Canada and Managing Director of European mergers and acquisitions with Merrill Lynch International. Mr. Hay spent the early part of his career as a practicing lawyer and taught part-time at both the University of Toronto and University of New Brunswick.

Mr. Hay also serves on the boards of EPCOR, SHAD (Chair), the Council of Clean and Reliable Energy and as Chair of the Acquisition Committee of the Beaverbrook Art Gallery. Prior directorships include Toronto Hydro-Electric System Limited where he was Vice-Chair.

Mr. Hay has a Bachelor of Laws from Osgoode Hall Law School, York University and a Bachelor of Arts from the University of Toronto (Victoria College) and holds his ICD.D.

**Timothy E. Hodgson**
Public Directorships (other than Hydro One and Hydro One Inc.):
Alignvest Acquisition II Corporation and MEG Energy Corp.

Public Board Interlocks: None

Mr. Hodgson has been a Managing Partner of Alignvest Management Corporation since 2012. Mr. Hodgson is also the Chief Compliance Officer of Alignvest Capital Management Inc. and Alignvest Investment Management Corporation. Mr. Hodgson was Special Advisor to Mr. Mark Carney, Governor of the Bank of Canada from 2010 to 2012, where he lead the Bank's market infrastructure initiatives to build a new repo clearinghouse business for Canada; reform Canada's over-the-counter derivatives markets; and review changes to systemically important market infrastructure businesses in Canada.

From 1990 to 2010, Mr. Hodgson held various positions in New York, London, Silicon Valley and Toronto with Goldman Sachs and served as Chief Executive Officer of Goldman Sachs Canada from 2005 to 2010 with overall responsibilities for the firm's operations, client relationships and regulatory matters in the region.

Mr. Hodgson currently sits on the boards of The Public Sector Pension Investment Board (PSP Investments), MEG Energy, Alignvest Acquisition II Corporation, and Next Canada. Mr. Hodgsons's prior directorships include The Global Risk Institute, KGS-Alpha Capital Markets, and the Richard Ivey School of Business. Mr. Hodgson also served on the board of Bridgepoint Health for eight years until July 2014.

Mr. Hodgson holds a Masters of Business Administration from The Richard Ivey School of Business at Western University and a Bachelor of Commerce from the University of Manitoba. He is a Chartered Professional Accountant (CPA), Chartered Accountant (CA) and holds his ICD.D.

**Jessica L. McDonald**
Public Directorships (other than Hydro One and Hydro One Inc.):
Coeur Mining Inc. and Trevali Mining Corporation

Public Board Interlocks: None

Ms. McDonald has been Chair of the Board of Directors and Interim President and Chief Executive Officer of Canada Post Corporation since 2017. From 2014 to 2017, she served as President and Chief Executive Officer of British Columbia Hydro & Power Authority. Ms. McDonald was also Executive Vice President of HB Global Advisors Corp., as well as a successful practice in mediation and negotiation on major commercial and industrial projects. In addition, Ms. McDonald has held many positions with the BC government, including the most senior public service position in the provincial government as Deputy Minister to the Premier, Cabinet Secretary and Head of the BC Public Service from 2005 to 2009, responsible for overseeing all aspects of government operations.

Ms. McDonald also serves on the boards of Coeur Mining Inc. and Trevali Mining Corporation, and is on the Member Council of Sustainable Development Technology Canada. Previous directorships include Powertech Labs (Chair) and Powerex Corp.

Ms. McDonald has a Bachelor of Arts (Political Science) from the University of British Columbia. She is also a member of the Institute of Corporate Directors and holds her ICD.D.

**Russel C. Robertson (provincial nominee)**
Public Directorships (other than Hydro One and Hydro One Inc.):
Bausch Health Companies Inc. and Turquoise Hill Resources Ltd.

Public Board Interlocks: None

Mr. Robertson is a corporate director and served as Executive Vice President and Head, Anti-Money Laundering, BMO Financial Group from 2008 to 2016. Mr. Robertson has served as Chief Financial Officer, BMO Financial Group and Executive Vice President, Business Integration where he oversaw the integration of Harris Bank and M&I Bank forming BMO Harris Bank. Before joining BMO, he spent over 35 years as a Chartered Professional Accountant holding various senior positions including the positions of Vice-Chair, Deloitte & Touche LLP (Canada) and Canadian Managing Partner, Arthur Andersen LLP (Canada).

Mr. Robertson has also served on the board of Bausch Health Companies Inc. since 2016 and acts as the chairperson of the Audit and Risk Committee and has served on the Board of Turquoise Hill Resources since 2012. Previous directorships include Virtus Investment Partners, Inc.

Mr. Robertson has a Bachelor of Arts (Honours) in Business Administration from the Ivey School of Business at the University of Western Ontario. He is a Chartered Professional Accountant (FCPA, FCA) and a Fellow of the Institute of Chartered Accountants (Ontario). He is also a member of the Institute of Corporate Directors and holds his ICD.D.

**William H. Sheffield**
Public Directorships (other than Hydro One and Hydro One Inc.):
Houston Wire & Cable Company, Velan Inc.

Public Board Interlocks: None

Mr. Sheffield is a corporate director. He is the former Chief Executive Officer of Sappi Fine Papers, headquartered in South Africa. Previously, he held senior roles with Abitibi-Consolidated, Inc. and Abitibi-Price, Inc. He began his career in the steel industry and held General Manager, Industrial Engineering and Cold Mill Operating roles at Stelco Inc.

Mr. Sheffield has served on the board of Houston Wire & Cable Company since 2006 where he acts as Chairman. Mr. Sheffield also serves on the boards of Velan, Inc., Burnbrae Farms Ltd., Longview Aviation Capital, Family Enterprise Xchange, and 4iiii Innovations Inc. Previous directorships include Canada Post Corporation, Ontario Power Generation, Corby Distilleries, Royal Group Technologies and SHAD.

Mr. Sheffield has a Bachelor of Science (Chemistry) from Carleton University and an MBA from McMaster University. Mr. Sheffield also holds his ICD.D and in 2015, he was awarded a Fellowship from the National Association of Corporate Directors in the US. He also completed the Family Enterprise Advisors Program (FEA) at the University of British Columbia.

**Melissa Sonberg**
Public Directorships (other than Hydro One and Hydro One Inc.):
Exchange Income Corporation

Public Board Interlocks: None

Ms. Sonberg is a corporate director and has been Adjunct Professor and Executive-in-Residence at McGill University's Desautel Faculty of Management since 2014. She spent the early part of her career in the healthcare industry before joining Air Canada, where she held leadership positions in a range of customer facing, operational and corporate functions. Ms. Sonberg was part of the founding executive team of Aeroplan, now part of AIMIA. Ms. Sonberg held positions of Senior Vice President, Human Resources & Corporate Affairs and Senior Vice President, Global Brands, Communications and External Affairs at AIMIA from 2001 to 2013.

Ms. Sonberg also serves on the boards of Exchange Income Corporation, MD Financial Holdings, Inc., Canadian Professional Sales Association, Group Touchette, Women in Capital Markets and Equitas – International Centre for Human Rights. Previous directorships include Rideau, Inc., Via Rail Canada, University of Ottawa, International Advisory Board and the McGill University Health Centre.

Ms. Sonberg has a Bachelor of Science (Psychology) from McGill University and a Masters of Health Administration from the University of Ottawa. She is a Certified Human Resource Executive and holds her ICD.D.

## Information Regarding Certain Directors and Executive Officers

As at December 31, 2018, the directors and executive officers of Hydro One and its subsidiaries beneficially owned, controlled or directed, directly or indirectly, as a group, 15,905 common shares, which represented approximately 0.003% of the outstanding common shares.

As at December 31, 2018, approximately 36.4% of the executives (those who hold a vice president role and above or equivalent) (12 out of 33) across Hydro One and its major subsidiaries, including 1 of 5 executive officers, are women.

## Corporate Cease Trade Orders and Bankruptcies

Except as described below:

- none of the directors or executive officers of Hydro One or Hydro One Inc. nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc. is, or within the last 10 years has served as, a director or executive officer of any company that, during such service or within a year after the end of such service, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;
- none of the directors or executive officers of Hydro One or Hydro One Inc. is, or within the last 10 years has served as, a director, CEO, or CFO of any company that, during such service or as a result of an event that occurred during such service, was subject to an order (including a cease trade order, or similar order or an order that denied access to any exemption under securities legislation), for a period of more than 30 consecutive days; or
- none of the directors or executive officers of Hydro One or Hydro One Inc. nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc., within the last 10 years has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director.

Blair Cowper-Smith served as a Director of Golfsmith International Holdings GP Inc. and Golf Town Canada Inc. (Golf Town) from 2016 to 2018. On September 14, 2016, Golf Town filed for and was granted Court bankruptcy protection under the CCAA. Golf Town emerged from Court protection after being sold to Fairfax Financial Holdings Limited and CI Investments Inc. in October 2016.

### Penalties or Sanctions

None of the directors or executive officers of Hydro One or Hydro One Inc., nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc., has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

### Conflicts of Interest

To the best of Hydro One's and Hydro One Inc.'s knowledge, there are no existing material potential conflicts of interest among Hydro One or any of its subsidiaries and the directors or executive officers of Hydro One or any of its subsidiaries as a result of their outside business interests as at the date hereof. Certain of the directors and executive officers serve as directors and executive officers of other public companies. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of Hydro One or Hydro One Inc. Where conflicts arise, they are managed through a variety of measures, including declaration of the conflict, recusal from meetings and/or portions of meetings, and the creation of separate board materials for the affected directors.

### Interest of Management and Others in Material Transactions

There are no material interests, direct or indirect, of any director or executive officer of Hydro One and its subsidiaries, or any associate or affiliate of any of the foregoing persons, in any transaction within the three years before the date hereof that has materially affected or is reasonably expected to materially affect Hydro One or Hydro One Inc.

### Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One or any of its subsidiaries had any outstanding indebtedness to Hydro One or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One or any of its subsidiaries.

### Independence Matters

The Board of Hydro One and Hydro One Inc. currently consists of 10 directors, all of whom are independent of Hydro One and Hydro One Inc. and independent of the Province within the meaning of the Governance Agreement.

For Hydro One's purposes, an independent director is one who is independent of Hydro One and independent of the Province. Directors will be independent of Hydro One if they are independent within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices and stock exchange requirements imposing a number or percentage of independent directors. Pursuant to Canadian securities laws, a director who is "independent" within the meaning of applicable securities laws is one who is free from any direct or indirect relationship which could, in the view of the board, be reasonably expected to interfere with a director's independent judgement, with certain specified relationships deemed to be non-independent. A director will be "independent of the Province" if he or she is independent of Hydro One under Ontario securities laws governing the disclosure of corporate governance practices, where the Province and certain specified provincial entities are treated as Hydro One's parent under that definition, but excluding current directors where the relationship ended before August 31, 2015. The Governance Agreement requires each of the directors, other than the CEO, to be both independent of Hydro One and independent of the Province. The Chair of Hydro One is independent of Hydro One and the Province.

The following table summarizes the committee memberships and independence status of Board members:

| | Committees | | | | Independence | |
|---|---|---|---|---|---|---|
| Director | Audit Committee | Governance Committee | Human Resources Committee | Health, Safety, Environment and Indigenous Peoples Committee | Independent of Hydro One | Independent of the Province |
| Cherie Brant | | v | | v | v | v |
| Blair Cowper-Smith | | v | v | | v | v |
| Anne Giardini | v | | | v | v | v |
| David Hay | v | | | v | v | v |
| Timothy Hodgson | | v | v | | v | v |
| Jessica McDonald | v | | v | | v | v |
| Russel Robertson | v | | v | | v | v |
| William Sheffield | v | | | v | v | v |
| Melissa Sonberg | | v | v | | v | v |
| Tom Woods | | | | | v | v |

## Diversity Policy

The Board has adopted a board diversity policy which formalizes the company's commitment to diversity and its desire to maintain a board comprising talented and dedicated directors whose skills, experience, knowledge and backgrounds reflect the diverse nature of the business environment in which it operates, including an appropriate number of female directors. The Board aspires towards a board composition in which each gender comprises at least 40% of the directors on the Board. Currently, the Board includes four female directors (40%).

## Director Attendance

Directors are expected to attend board meetings, meetings of the committees on which they serve and the annual meeting of shareholders.

**Number of Board and Committee Meetings (August 13, 2018 to December 31, 2018)[1]:**

| | Regular | Non-Regular | In Camera Sessions |
|---|---|---|---|
| Board | 2 | 11 | 13 |
| Audit Committee | 1 | 4 | 5 |
| Health, Safety, Environment and Indigenous Peoples Committee | 1 | – | 1 |
| Human Resources Committee | 2 | 3 | 5 |
| Governance Committee | 1 | 3 | 4 |

1 All of the current directors were appointed directors of Hydro One effective August 13, 2018. The directors of Hydro One are also directors of Hydro One Inc. and the two boards and each committee thereof hold joint meetings.

## Audit Committee

The Audit Committee must consist of at least three directors, all of whom are persons determined by Hydro One to be both "independent" (within the meaning of all Canadian securities laws and stock exchange requirements and the Governance Agreement) and "financially literate" (within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including National Instrument 52-110 – *Audit Committees*). At least one member of the Audit Committee will qualify as an "audit committee financial expert" as defined by the applicable rules of the US Securities and Exchange Commission. The Audit Committee comprises William Sheffield (Chair), Anne Giardini, David Hay, Jessica McDonald and Russel Robertson. Each of the Audit Committee members is independent and financially literate and each has an understanding of the accounting principles used to prepare Hydro One's financial statements and varied experience as to the general application of such accounting principles, as well as an understanding of the internal controls and procedures necessary for financial reporting. Russel Robertson and David Hay each qualify as an audit committee financial expert.

Please refer to the biographies of our Audit Committee members described under "– Directors and Executive Officers" above for details of their additional invaluable skills and experience.

## Human Resource Committee

Hydro One's management team, the Human Resources Committee and the Company's compensation advisors all play a key role in determining executive compensation for the company's directors and executives and in managing compensation risk on behalf of the Board of Hydro One. The Human Resources Committee is responsible for assisting the Board in fulfilling its oversight responsibilities relating to the attraction and retention of key senior management.

All of the members of the Human Resources Committee are independent. The Human Resources Committee comprises Melissa Sonberg (Chair), Blair Cowper-Smith, Timothy Hodgson, Jessica McDonald and Russel Robertson. All of the members of the Human Resources Committee have gained the following relevant experience in human resources and compensation by serving as an executive officer (or equivalent) of a major organization and/or through prior service on the compensation committee of a stock exchange listed company or otherwise:

- human resources experience (experience with benefit, pension and compensation programs (in particular, executive compensation));
- risk management experience (knowledge and experience with internal risk controls, risk assessments and reporting as it pertains to executive compensation); and
- executive leadership experience (experience as a senior executive/officer of a public company or major organization).

Please refer to the biographies of our Human Resources Committee members described under "– Directors and Executive Officers" above for details of their additional invaluable skills and experience.

## CEO Selection Committee

The Board has also formed an ad hoc CEO Selection Committee to identify and select a President and CEO.

## Compensation Policies and Practices

Other than as set forth in Hydro One's management information circular dated March 19, 2018 prepared in connection with the annual meeting of shareholders held on May 15, 2018 or as otherwise described below, there have been no material changes to the policies and practices adopted by the Board of Hydro One or Hydro One Inc. to determine compensation for Hydro One's or Hydro One Inc.'s directors and executive officers since January 1, 2018.

## Changes to Hydro One's Board and CEO Compensation

As disclosed under "– Directors and Executive Officers" above, on July 11, 2018, Hydro One, on behalf of itself and Hydro One Inc., announced that it had entered into the Letter Agreement for the purpose of the orderly replacement of the Board of Hydro One and Hydro One Inc. and the retirement of Mayo Schmidt as the CEO effective July 11, 2018. In accordance with the Letter Agreement, Hydro One has agreed to consult with the Province in respect of future matters of executive compensation. In addition, the then-existing Hydro One and Hydro One Inc. Board volunteered and agreed to immediately reduce board compensation to the levels contemplated by the pre-January 1, 2018 director compensation policy. The then-existing Hydro One and Hydro One Inc. Board also volunteered and agreed to forego any compensation for their service after June 30, 2018.

In connection with Mr. Schmidt's retirement, he received amounts consistent with Hydro One's retirement policies applicable to his outstanding equity awards and his employment agreement as previously disclosed and was not entitled to severance. Mr. Schmidt received a $0.4 million lump sum payment in lieu of all post-retirement benefits and allowances.

### Urgent Priorities Act (formerly, Bill 2)

In July 2018, the Province introduced the *Urgent Priorities Act, 2018* (Urgent Priorities Act), which amended the *Ontario Energy Board Act, 1998* (OEB Act) and introduced the *Hydro One Accountability Act* (Accountability Act). The Accountability Act came into force in August 2018. The Accountability Act requires the Board to establish a new compensation framework for the Board, the CEO and other executives, in consultation with the Province and the other five largest shareholders of Hydro One Limited (which framework must include policies governing severance and other entitlements in connection with any termination of employment). The new compensation framework is not effective until approved by Management Board of Cabinet of the Province. In addition, the Management Board of Cabinet of the Province has the authority to issue directives governing the compensation of directors and certain executives of Hydro One and its subsidiaries (excluding subsidiaries incorporated outside Canada). In February 2019, the Board published a revised compensation framework that complies with the requirements of the Urgent Priorities Act. The Accountability Act also requires Hydro One to annually provide public disclosure concerning compensation paid to certain executives. The Accountability Act may adversely impact Hydro One and Hydro One Inc.'s ability to continue to attract and retain executives.

The OEB Act was amended to preclude the OEB from approving or fixing rates for Hydro One or any of its subsidiaries that include any amount in respect of compensation paid to the CEO and other executives. The impact of this amendment is expected to restrict Hydro One's ability to recover certain amounts paid for executive compensation through separate rate mechanisms, which is expected to result in a reduction to Hydro One's net income for the year ending December 31, 2019 of up to $14 million and is subject to a final determination by the OEB. The reduction may be materially lower, depending on the determination by the OEB of the executives whose compensation is to be excluded. The Urgent Priorities Act expressly provides that certain causes of action and proceedings are not available or will be barred against the Province, Hydro One or any of its subsidiaries, or any of its current or former officers, directors, employees or agents in respect of the Accountability Act, the Province's involvement in compensation matters or other aspects of the corporate governance of Hydro One or any of its subsidiaries or any alleged misrepresentation in any prospectus, document or other public statement related to the involvement of the Province in compensation matters at Hydro One or any of its subsidiaries.

### Province of Ontario

Notwithstanding the Governance Agreement, and in light of actions taken by the Province following the provincial election in June 2018 including the passage of the Urgent Priorities Act, the Province may elect to make further decisions relevant to Hydro One that could be detrimental to the interests of various stakeholders of Hydro One.

## HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,700 regular employees and 2,200 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2018:

| | Regular Employees | Non-Regular Employees | Total |
|---|---|---|---|
| Power Workers' Union (PWU)[1] | 3,583 | 856 | 4,439 |
| Society of United Professionals (Society) | 1,458 | 36 | 1,494 |
| Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2] | — | 1,277 | 1,277 |
| Total employees represented by unions | 5,041 | 2,169 | 7,210 |
| Management and non-represented employees | 667 | 22 | 689 |
| Total employees[3] | 5,708 | 2,191 | 7,899 |

1 Includes 715 non-regular "hiring hall" employees covered by the PWU agreement.

2 The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

3 The average number of Hydro One employees in 2018 was approximately 8,600, consisting of approximately 5,650 regular employees and approximately 2,950 non-regular employees.

### Collective Agreements

On March 1, 2018, Hydro One insourced its customer service operations (CSO), which had been previously outsourced to Inergi LP and Vertex Customer Management (Canada) Limited since 2002. The insourcing was facilitated through labour agreements reached with the PWU and the Society (formerly the Society of Energy Professionals) in 2017.

The prior collective agreement with the PWU expired on March 31, 2018. On March 26, 2018, Hydro One and the PWU reached a tentative agreement, and on June 27, 2018, the agreement was ratified by the PWU. The term of the agreement is for two years ending on March 31, 2020.

### Stock-based Compensation

During 2018 and 2017, the Company granted awards under its LTIP, consisting of Performance Share Units (PSUs), Restricted Share Units (RSUs), and Stock Options, all of which are equity settled. At December 31, 2018 and 2017, the following LTIP awards were outstanding:

| December 31 (number of units) | 2018 | 2017 |
|---|---|---|
| PSUs | **605,180** | 429,980 |
| RSUs | **442,470** | 393,430 |
| Stock Options | **949,910** | – |

## NON-GAAP MEASURES

### FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Net cash from operating activities | **1,575** | 1,716 |
| Changes in non-cash balances related to operations | **23** | (113) |
| Preferred share dividends | **(18)** | (18) |
| Distributions to noncontrolling interest | **(8)** | (6) |
| **FFO** | **1,572** | 1,579 |

### Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs and income related to the Avista Corporation acquisition, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses, from net income attributable to common shareholders. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and loss or gain on the foreign exchange contract, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses. It provides users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

| Year ended December 31 (millions of dollars, except number of shares and EPS) | 2018 | 2017 |
|---|---|---|
| Net income (loss) attributable to common shareholders | **(89)** | 658 |
| Impacts related to Avista Corporation acquisition: | | |
| OM&A – Avista Corporation-related costs (before tax) | **11** | 20 |
| Financing charges – Avista Corporation-related costs (before tax) | **58** | 22 |
| Financing charges – loss (gain) on foreign exchange contract (before tax) | **(25)** | 3 |
| Tax impact | **(15)** | (9) |
| Avista Corporation-related impacts (after tax) | **29** | 36 |
| Impacts related to OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses: | | |
| Reversal of revenues | **68** | – |
| Deferred tax expense | **799** | – |
| OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses impacts (after tax) | **867** | – |
| Adjusted net income attributable to common shareholders | **807** | 694 |
| Weighted average number of shares | | |
| Basic | **595,756,470** | 595,287,586 |
| Effect of dilutive stock-based compensation plans | **2,147,473** | 2,234,665 |
| Diluted | **597,903,943** | 597,522,251 |
| Adjusted EPS | | |
| Basic | **$ 1.35** | $ 1.17 |
| Diluted | **$ 1.35** | $ 1.16 |

### Revenues, Net of Purchased Power

Revenues, net of purchased power is defined as revenues less the cost of purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Revenues | **6,150** | 5,990 |
| Less: Purchased power | **2,899** | 2,875 |
| **Revenues, net of purchased power** | **3,251** | 3,115 |

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Distribution revenues | **4,422** | 4,366 |
| Less: Purchased power | **2,899** | 2,875 |
| **Distribution revenues, net of purchased power** | **1,523** | 1,491 |

FFO, basic and diluted Adjusted EPS, Adjusted Net Income, Revenues, Net of Purchased Power, and Distribution Revenues, Net of Purchased Power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

## RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2018. The IESO, OPG, Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. The following is a summary of the Company's related party transactions during the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)

| Related Party | Transaction | 2018 | 2017 |
|---|---|---|---|
| **Province** | Dividends paid | **275** | 301 |
| **IESO** | Power purchased | **1,636** | 1,583 |
| | Revenues for transmission services | **1,615** | 1,521 |
| | Amounts related to electricity rebates | **477** | 357 |
| | Distribution revenues related to rural rate protection | **239** | 247 |
| | Distribution revenues related to the supply of electricity to remote northern communities | **35** | 32 |
| | Funding received related to CDM programs | **62** | 59 |
| **OPG** | Power purchased | **10** | 9 |
| | Revenues related to provision of services and supply of electricity | **9** | 8 |
| | Costs related to the purchase of services | **—** | 1 |
| **OEFC** | Power purchased from power contracts administered by the OEFC | **2** | 2 |
| **OEB** | OEB fees | **8** | 8 |

## RISK MANAGEMENT AND RISK FACTORS

### Risks Relating to Hydro One's Business

#### Regulatory Risks and Risks Relating to Hydro One's Revenues

*Risks Relating to Obtaining Rate Orders*

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

*Risks Relating to Actual Performance Against Forecasts*
The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful CDM programs whose results exceed forecasted expectations.

*Risks Relating to Regulatory Treatment of Deferred Tax Asset*
As a result of leaving the payments in lieu of corporate income taxes (PILs) Regime and entering the federal tax regime in connection with the IPO of the Company, Hydro One recorded additional deferred tax assets due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. At the time of the IPO, the Company determined the tax savings derived from the additional deferred tax assets should accrue to the shareholders of Hydro One Limited. The OEB's September 28, 2017 decision (Original Decision) (see details above in "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission") altered Hydro One's allocation of the tax savings derived from the additional deferred tax assets and determined a portion of the tax savings should be accrued to the ratepayers. In October 2017, the Company filed a motion to review and vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (Appeal) which was stayed pending the outcome of the Motion. In both cases, the Company's position was that the OEB made errors of fact and law in its determination of the allocation of the tax savings between the shareholders and ratepayers.

On March 7, 2019, the OEB issued a decision upholding its Original Decision on the handling of the deferred tax asset. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks' 2018–2022 distribution rates in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. Based on these decisions, the Company recognized a total one-time $867 million decrease to net income, which represents the amount of $885 million as previously disclosed, reduced by $18 million related to forgone revenue and net tax recovery adjustments. The Company is currently considering its options with respect to the Appeal.

*Risks Relating to Other Applications to the OEB*
The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

*Risks Relating to Rate-Setting Models for Transmission and Distribution*
The OEB approves and periodically changes the rate-setting models and methodology for the transmission and distribution businesses. Changes to the application type, filing requirements, rate-setting methodology, or revenue requirement determination may have a material negative impact on Hydro One's revenue and net income. For example, the OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be for multi-year periods. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

When rates are set for a multi-year period, including under a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the multi-year period, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

*Risks Relating to Capital Expenditures*

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

*Risk of Recoverability of Total Compensation Costs*

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company.

The changes flowing from the Urgent Priorities Act are expected to restrict Hydro One's ability to recover certain amounts paid for executive compensation through separate rate mechanisms, which is estimated to result in a reduction in Hydro One's net income for the year ending December 31, 2019 of up to $14 million, and is subject to a final determination by the OEB. The reduction may be materially lower, depending on the determination by the OEB of the executives whose compensation is to be excluded.

**Risks Relating to Government Action**

The Province is, and is likely to remain, the largest shareholder in Hydro One Limited. The Province may be in a position of conflict from time to time as a result of being an investor in Hydro One Limited and also being a government actor setting broad policy objectives in the electricity industry. Government actions may not be in the interests of the Company or investors.

Governments may pass legislation or regulation at any time, including legislation or regulation impacting Hydro One, which could have potential material adverse effects on Hydro One and its business. Such government actions may include, but are not limited to, legislation, regulation, directives or shareholder action intended to reduce electricity rates, place constraints on compensation, or affect the governance of Hydro One (for example, potential government actions relating to the Province's election promise to reduce hydro rates by 12%). Such government actions could adversely affect the Company's financial condition and results of operations, as well as public opinion and the Company's reputation. Government action may also hinder Hydro One's ability to pursue its strategy and/or objectives.

Additionally, involvement by the Province in placing constraints on executive compensation may inhibit the Company's ability to attract and retain qualified executive talent, which may also impact the Company's performance, strategy and/or objectives. The failure to attract and retain qualified executives could have a material adverse effect on the Company.

In June 2018, Moody's downgraded the long-term debt rating for Hydro One Inc. and in September 2018, S&P lowered its issuer credit ratings on the Company and Hydro One Inc. (as detailed above in the "Credit Ratings" section). These ratings downgrades reflect the ratings agencies' assessment of government involvement in the business of Hydro One. The Company cannot predict what actions rating agencies may take in the future, positive or negative, including in response to government action or inaction relating to or impacting Hydro One. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and a downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt.

**Executive Recruitment and Retention Risk**

Involvement by the Province relating to executive compensation, and Hydro One executive compensation constraints flowing from the Urgent Priorities Act may inhibit the Company's ability to attract and retain qualified executive talent. The Company's strategy is tied to its ability to continue to attract and retain qualified executives. The failure to attract and retain qualified executives could have a material adverse effect on the Company.

**Management Retention**
In the fourth quarter of 2018, the Company entered into retention agreements with certain of its key officers, namely Messrs. Dobson, Kiraly, Meneley, Scarlett, Lopez and Ms. McKellar, in order to ensure stability in the organization and to allow the Company sufficient time to complete its recruitment of a new CEO and support the transition to a renewed senior management team. The retention arrangements are intended to ensure the continued employment of those officers for periods ranging from February 28, 2019 through May 31, 2019 depending on the officer. The retention agreements generally confirm, among other things, that so long as the individual does not resign prior to a specified date (being the retention date), certain key terms (other than severance) of the individual's employment arrangements will be respected, including the vesting of his or her outstanding share-based awards and a pro-rata portion of his or her short-term and long-term incentive in respect of the 2019 fiscal year. To date, Mr. Meneley has notified the Company that he intends to resign effective March 1, 2019, and Ms. McKellar has notified the Company that she intends to retire effective April 1, 2019. The retention agreements may be extended by mutual agreement, however, there is no assurance that any of the key officers will remain after their retention dates, in which case the Company could have a lack of senior management to run the Company's business. While the Company has succession plans in place for certain key officers, there is no assurance that there will not be an impact on the Company's business if any or all such key officers resign before, on, or after, their respective retention dates. In addition, there is no assurance that the Company will be able to attract and retain qualified replacement officers on a timely basis, or at all, in order to replace these individuals. The failure to attract and retain qualified officers could have a material adverse effect on the Company.

**Indigenous Claims Risk**
Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada)) (Reserve) lands, or lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories (land traditionally occupied or used by a First Nation, Metis or Inuit group) and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, including communities with a traditional governance model not recognized under the *Indian Act*, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

**Risk from Transfer of Assets Located on Reserves**
The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

**Compliance with Laws and Regulations**
Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "– Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the NERC and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may reduce Hydro One's revenue, or may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates. For example, the federal government's November 2018 Fall Economic Statement announced measures related to accelerated investment incentives which, if implemented, could have a material adverse impact on Hydro One.

### Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. Climate change may have the effect of shifting weather patterns and increasing the severity and frequency of extreme weather events and natural disasters, which could impact Hydro One's business. The Company's facilities may not withstand occurrences of these types in all circumstances. The Company could also be subject to claims for damages from events which may be proximately connected with the Company's assets (for example, forest fires), claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for the Company's other assets and for damage claims, such insurance coverage may have deductibles, limits and/or exclusions that may still expose the Company to material losses. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas.

### Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex IT systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and IT, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of IT security for its assets that are not subject to these mandatory standards. The Company must also comply with various cyber-security and privacy-related regulatory requirements under the OEB's Ontario Cyber Security Framework and legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and IT systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

### Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a two-year term, covering the period from April 1, 2018 to March 31, 2020. The Company also reached a renewal collective agreement with the CUSW for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements were also reached with the Society and the PWU to facilitate the insourcing of CSO services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company. Collective agreements requiring renewal in 2019 include the Society agreement and the PWU CSO agreement, expiring on March 31, 2019 and September 30, 2019, respectively.

### Work Force Demographic Risk

By the end of 2018, approximately 16% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2019, approximately 18% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2018, approximately 4% of the Company's work force (down from 5% in 2017) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

**Risk Associated with Arranging Debt Financing**

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including $731 million in 2019, $653 million in 2020, and $803 million in 2021. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would mature within one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2019 and 2020. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Company to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company.

**Market, Financial Instrument and Credit Risk**

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk. In the future, the Company may be exposed to additional foreign exchange risk in connection with other acquisitions or transactions in which it completes in a currency other than Canadian dollars. Although the Company may attempt to mitigate such risk through hedging transactions, there can be no assurance any such hedge will fully mitigate the risk of currency exchange fluctuations.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2020 net income by approximately $25 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

**Risks Relating to Asset Condition and Capital Projects**

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

### Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company. The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "$SF_6$". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

### Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2017, and was filed in April 2018, covering a three-year period from 2018 to 2020. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2020 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and other post-employment benefits (OPEB) amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "– Other Post-Employment and Post-Retirement Benefits Risks".

### Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

### Risk Associated with Outsourcing Arrangements

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

### Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

### Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company. See also "Other Developments – Litigation – Class Action Lawsuit".

One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed by two Avista Corporation shareholders in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in Fink has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One. See also "Other Developments – Litigation – Litigation Relating to the Merger".

### Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned or controlled lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

### Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

### Risks Associated with Acquisitions

While the Company has experience in operating in the Ontario electricity market, if it were to pursue acquisitions in other markets it would need to develop or obtain additional expertise in these new markets. Such acquisitions would include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs. Realization of the anticipated benefits would depend, in part, on the Company's ability to successfully integrate the acquired business, including the requirement to devote management attention and resources to integrating business practices and support functions. The failure to realize the anticipated benefits, the diversion of management's attention, or any delays or difficulties encountered in connection with the integration could have an adverse effect on the Company's business, results of operations, financial condition or cash flows.

## Risks Relating to the Company's Relationship with the Province

### Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 47.4% of the outstanding common shares of Hydro One. The Electricity Act restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the Governance Agreement. Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other investors. Notwithstanding the Governance Agreement, and in light of actions taken by the Province following the provincial election in June 2018, there can be no assurance that the Province will not take other actions in the future that could be detrimental to the interests of investors in Hydro One. See "Risks Relating to Government Action" above.

The share ownership restrictions in the *Electricity Act* (Share Ownership Restrictions) and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

**Nomination of Directors and Confirmation of CEO and Chair**
Although director nominees (other than the CEO) are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the CEO.

**Board Removal Rights**
Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board, including in each case its own director nominees but excluding the CEO and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other stakeholders of Hydro One.

**More Extensive Regulation**
Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company. See "Risks Relating to Government Action" above.

**Prohibitions on Selling the Company's Transmission or Distribution Business**
The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

**Future Sales of Common Shares by the Province**
Although the Province has indicated that it does not intend to sell further common shares of Hydro One, the registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

**Limitations on Enforcing the Governance Agreement**
The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

## CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

### Revenues
Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

### Regulatory Assets and Liabilities
Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include amounts related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, forgone revenue, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that

the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

## Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

## Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

### Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2018 increased to 3.90% (from 3.40% at December 31, 2017) for pension benefits and increased to 4.00% (from 3.40% at December 31, 2017) for the post-retirement and post-employment plans. The increase in the discount rate has resulted in a corresponding decrease in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

### Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets of 6.50% is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's investment policy effective November 11, 2016. A new investment policy was adopted by Hydro One effective May 14, 2018 which will be implemented over the next several years. Hydro One's current expectation is that the new investment policy will not be fully implemented until 2021-2022. As such, with the implementation timing noted above, the investment policy effective November 11, 2016 would continue to be appropriate for the December 31, 2018 disclosures and the 2019 registered pension plan expense.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

### Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.60% per annum as at December 31, 2017 to approximately 1.40% per annum as at December 31, 2018. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2018.

### Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflects negotiated salary increases over the contract period.

### Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2018 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

**Rate of Increase in Health Care Cost Trends**

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends used for 2017 and 2018 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $23 million increase in 2018 interest cost plus service cost, and a $230 million increase in the benefit liability at December 31, 2018.

### Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

### Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2018, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2018. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

## DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are the processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its CEO and CFO, as appropriate, to make timely decisions regarding required disclosure in the MD&A and financial statements. At the direction of the Company's CEO and CFO, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective as at December 31, 2018.

Internal control over financial reporting is designed by, or under the direction of the CEO and CFO to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the CEO and CFO, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the criteria established in the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as at December 31, 2018.

Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

There were no changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

## NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

### Recently Adopted Accounting Guidance

| Guidance | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| ASC 606 | May 2014 – November 2017 | ASC 606 *Revenue from Contracts with Customers* replaced ASC 605 *Revenue Recognition*. ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. | January 1, 2018 | On January 1, 2018, Hydro One adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption. |
| ASU 2017-07 | March 2017 | Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable. | January 1, 2018 | Hydro One applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 – Significant Accounting Policies and Note 12 – Regulatory Assets and Liabilities. |

### Recently Issued Accounting Guidance Not Yet Adopted

| Guidance | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2016-02<br>2018-01<br>2018-10<br>2018-11<br>2018-20 | February 2016 – December 2018 | Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties. | January 1, 2019 | Hydro One reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to Hydro One's financial statements will be the recognition of approximately $27 million Right-of-Use (ROU) assets and corresponding lease obligations on the Consolidated Balance Sheet. The ROU assets and lease obligations represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to the Company's incremental borrowing rate. |

| Guidance | Date issued | Description | Effective date | Anticipated impact on Hydro One |
|---|---|---|---|---|
| 2018-07 | June 2018 | Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees. | January 1, 2019 | No impact upon adoption |
| 2018-13 | August 2018 | Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes. | January 1, 2020 | Under assessment |
| 2018-14 | August 2018 | Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes. | January 1, 2021 | Under assessment |
| 2018-15 | August 2018 | The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment. | January 1, 2020 | Under assessment |

## SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

| Three months ended December 31 (millions of dollars, except EPS) | 2018 | 2017 | Change |
|---|---|---|---|
| **Revenues** | | | |
| Distribution | **1,138** | 1,049 | 8.5% |
| Transmission | **342** | 379 | (9.8%) |
| Other | **11** | 11 | 0.0% |
| | **1,491** | 1,439 | 3.6% |
| **Costs** | | | |
| Purchased power | **741** | 662 | 11.9% |
| OM&A | | | |
| Distribution | **167** | 146 | 14.4% |
| Transmission | **114** | 79 | 44.3% |
| Other | **27** | 19 | 42.1% |
| | **308** | 244 | 26.2% |
| Depreciation, amortization and asset removal costs | **217** | 214 | 1.4% |
| | **1,266** | 1,120 | 13.0% |
| **Income before financing charges and income taxes** | **225** | 319 | (29.5%) |
| Financing charges | **123** | 119 | 3.4% |
| **Income before income taxes** | **102** | 200 | (49.0%) |
| Income taxes | **800** | 38 | 2,005.3% |
| **Net income (loss)** | **(698)** | 162 | (530.9%) |
| **Net income (loss) attributable to common shareholders of Hydro One** | **(705)** | 155 | (554.8%) |
| Basic EPS | **$ (1.18)** | $ 0.26 | (553.8%) |
| Diluted EPS | **$ (1.18)** | $ 0.26 | (553.8%) |
| Basic Adjusted EPS | **$ 0.30** | $ 0.29 | 3.4% |
| Diluted Adjusted EPS | **$ 0.29** | $ 0.28 | 3.6% |
| **Capital Investments** | | | |
| Distribution | **168** | 161 | 4.3% |
| Transmission | **292** | 267 | 9.4% |
| Other | **7** | 3 | 133.3% |
| | **467** | 431 | 8.4% |
| **Assets Placed In-Service** | | | |
| Distribution | **253** | 207 | 22.2% |
| Transmission | **698** | 522 | 33.7% |
| Other | **1** | 4 | (75.0%) |
| | **952** | 733 | 29.9% |

### Net Income (Loss)

Net loss attributable to common shareholders for the quarter ended December 31, 2018 of $705 million is a decrease of $860 million or 554.8% from the prior year net income. Significant influences on earnings included:

- increase in transmission and distribution revenues due to higher energy consumption resulting from favourable weather;
- higher transmission revenues driven by increased OEB-approved transmission rates;
- higher OM&A costs primarily resulting from:
  - higher vegetation management costs resulting from a change to an improved vegetation program resulting in greater coverage and better reliability,
  - higher property taxes, primarily due to non-recurring favourable re-assessment of payments in lieu of property taxes in 2017,
  - higher stations and lines maintenance costs,
  - insurance proceeds received in Q4 2017,
  - higher HST recovery in 2017, and
  - higher costs related to the Merger;
- higher income tax expense primarily attributable to a charge to deferred tax expense of $799 million related to the OEB's deferred tax asset and distribution rates decisions, partially offset by higher temporary differences arising from a combination of higher in-service additions, the asset mix and higher pension and OPEB contributions in excess of accounting expense in the fourth quarter of 2018, compared to 2017.

### EPS and Adjusted EPS

EPS was ($1.18) for the fourth quarter of 2018, compared to $0.26 in 2017. The decrease in EPS was driven by lower earnings for the fourth quarter of 2018, as discussed above. Adjusted EPS was $0.30 in the fourth quarter of 2018, compared to $0.29 in 2017. The increase in Adjusted EPS was driven by higher net income for the fourth quarter of 2017, net of impacts related to the Merger and the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses.

### Revenues

The quarterly decrease of $37 million or 9.8% in transmission revenues was primarily due to impacts of the OEB's deferred tax asset decision, partially offset by higher revenues driven by increased OEB-approved transmission rates for 2018, and higher average monthly Ontario 60-minute peak demand driven by favourable weather in the fourth quarter of 2018.

The quarterly increase of $10 million or 2.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption resulting from favourable weather in the fourth quarter of 2018 and higher deferred regulatory adjustments; partially offset by lower CDM revenue.

### OM&A Costs

The quarterly increase of $35 million or 44.3% in transmission OM&A costs was primarily due to a non-recurring reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation in 2017, higher volume of demand maintenance work on power equipment and overhead lines, insurance proceeds received in 2017 due to equipment failures at the Fairchild and Campbell transmission stations, and higher volume of work on vegetation management.

The quarterly increase of $21 million or 14.4% in distribution OM&A costs was primarily due to higher volume of work on vegetation management, and higher volume of emergency calls, partially offset by lower storm restoration costs, and lower costs related to the renewed IT contract.

A further increase of $8 million in other OM&A is driven primarily by higher costs related to the Merger.

### Financing Charges

The quarterly increase of $4 million or 3.4% in financing charges was primarily due to an increase in interest expense on long-term debt resulting from an increase in weighted-average long-term debt balance outstanding during the quarter, partially offset by an unrealized loss recorded in 2017 due to revaluation of the foreign exchange contract related to the Merger.

### Income Taxes

Income tax expense for the fourth quarter of 2018 increased by $762 million compared to 2017, and the Company realized an ETR of approximately 784.3% in the fourth quarter of 2018, compared to approximately 19.0% realized in 2017. This was primarily attributable to a charge to deferred tax expense of $799 million related to the OEB's deferred tax asset and distribution rates decisions (see section "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission" for details). This increase was partially offset by an increase in tax deductions arising from higher in-service additions coupled with an increased allocation to a higher depreciation class, as well as higher pension and other post-employment benefit (OPEB) contributions for tax purposes. The Company is required to accrue taxes based on the tax liability without considering the temporary differences as prescribed by the regulator.

### Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- assets placed in-service in the fourth quarter of 2018 for station sustainment investments, including Horning, Centralia, London Nelson, St. Isidore, Wanstead, Palmerston, Chenaux, and Dryden transmission stations, as well as the Bruce Special Protection System end-of-life equipment replacement project;
- higher volume of demand work placed in-service associated with equipment failures; and
- higher volume of overhead lines and component replacement work placed in-service; partially offset by
- substantial investments in major development projects placed in-service in 2017, including Leamington and Holland transmission stations; and
- assets placed in-service in the fourth quarter of 2017 for station sustainment investments, including OverBrook, Hanmer, and Leaside transmission stations.

The increase in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of investments placed in-service for system capability reinforcement projects;
- cumulative investments in the Advanced Distribution System project placed in-service in 2018; and
- cumulative investments in distribution generation connection projects placed in-service in 2018; partially offset by
- the completion of the Company's website redesign project to improve customer service and operational efficiencies; and
- timing of demand work on large joint-use and line relocation projects.

#### Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to the following:

- higher volume of overhead lines refurbishments and replacements;
- higher volume of demand work associated with equipment failures;
- higher volume of work required to adhere to the NERC Cyber Security standards;
- timing of project work on major development projects, including the Niagara Reinforcement, Lake Superior Link, and East-West Tie Connection projects, as well as work at Clarington and Holland transmission stations; and
- higher volume of spare transformer purchases; partially offset by
- lower volume of transmission station refurbishments and replacements work.

The increase in distribution capital investments during the fourth quarter was primarily due to the following:

- higher spend on joint use and line relocation projects due to timing of capital contributions; and
- increased volume of emergency power and storm restorations work due to higher storm activity in 2018.

## HYDRO ONE HOLDINGS LIMITED – UNAUDITED CONSOLIDATING SUMMARY FINANCIAL INFORMATION

Hydro One Limited fully and unconditionally guarantees the payment obligations of its wholly-owned subsidiary Hydro One Holdings Limited (HOHL) issuable under the short form base shelf prospectus dated November 23, 2018. Accordingly, the following consolidating summary financial information is provided in compliance with the requirements of section 13.4 of National Instrument 51-102 – *Continuous Disclosure Obligations* providing for an exemption for certain credit support issuers. The tables below contain consolidating summary financial information as at and for the years ended December 31, 2018 and December 31, 2017 for: (i) Hydro One Limited; (ii) HOHL; (iii) the subsidiaries of Hydro One Limited, other than HOHL, on a combined basis, (iv) consolidating adjustments, and (v) Hydro One Limited and all of its subsidiaries on a consolidated basis, in each case for the periods indicated. Such summary financial information is intended to provide investors with meaningful and comparable financial information about Hydro One Limited and its subsidiaries. This summary financial information should be read in conjunction with Hydro One Limited's most recently issued annual financial statements. This summary financial information has been prepared in accordance with US GAAP, as issued by the FASB.

| For the year ended December 31 (millions of dollars, unaudited) | Hydro One Limited | | HOHL | | Subsidiaries of Hydro One Limited, other than HOHL | | Consolidating Adjustments | | Total Consolidated Amounts of Hydro One Limited | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Revenue | **12** | 16 | **—** | — | **6,243** | 6,053 | **(105)** | (79) | **6,150** | 5,990 |
| Net Income (Loss) Attributable to Common Shareholders | **(74)** | (43) | **22** | (3) | **47** | 745 | **(84)** | (41) | **(89)** | 658 |

| As at December 31 (millions of dollars, unaudited) | Hydro One Limited | | HOHL | | Subsidiaries of Hydro One Limited, other than HOHL | | Consolidating Adjustments | | Total Consolidated Amounts of Hydro One Limited | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 | **2018** | 2017 |
| Current Assets | **159** | 117 | **22** | — | **2,054** | 1,444 | **(744)** | (542) | **1,491** | 1,019 |
| Non-Current Assets | **5,799** | 6,423 | **—** | — | **41,597** | 41,745 | **(23,230)** | (23,486) | **24,166** | 24,682 |
| Current Liabilities | **97** | 83 | **—** | 3 | **4,391** | 3,933 | **(1,460)** | (1,279) | **3,028** | 2,740 |
| Non-Current Liabilities | **1,516** | 1,514 | **3** | — | **22,373** | 21,403 | **(10,906)** | (10,209) | **12,986** | 12,708 |

## FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the Operating Credit Facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; expectations regarding the deferred tax asset; the Appeal; the OEB; the Exemptive Relief; NRLP and the Niagara Reinforcement Project, the Lake Superior Link Project, and related regulatory applications; the Company's share capital and conversion of outstanding awards under the share grant plans and the LTIP; collective agreements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of post-employment benefit costs; dividends; credit ratings and related risks; Hydro One's strategy; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; recent accounting-related guidance; the Universal Base Shelf Prospectus; the US Debt Shelf Prospectus; the Demand Facility; the Company's acquisitions and mergers, including Orillia Power and Peterborough Distribution; expected outcomes and impacts relating to the termination of the Merger; the Urgent Priorities Act, the Accountability Act, and anticipated impacts; Hydro One's new compensation framework; expectations relating to executive compensation and potential impacts on Hydro One; anticipated and potential senior management departures and possible impacts; retention arrangements; the Company's ability to attract and retain qualified officers; risk associated with acquisitions; anticipated impact of measures related to accelerated investment initiatives; climate change; cyber and data security; expectations related to work force demographics; class action litigation, including litigation relating to the Merger; foreign exchange risk; the Province's ownership of Hydro One, and conflicts that may arise between the Province and Hydro One from time to time; government actions and the potential impacts on Hydro One and its business; future sales of shares of Hydro One; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market or for Hydro One specifically; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; no significant changes to the Company's current credit ratings; no unforeseen impacts of new accounting pronouncements; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures, or denials of applications;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- risks associated with the Province exercising further legislative and regulatory powers in the implementation of the Urgent Priorities Act and the Accountability Act;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the Indian Act (Canada));
- the risks associated with information system security and maintaining a complex IT system infrastructure;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- the risk of a credit rating downgrade and its impact on the Company's funding and liquidity;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future egulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP;
- the impact of the ownership by the Province of lands underlying the Company's transmission system; and
- the risk related to the impact of the new accounting pronouncements.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

# Management's Report

The Amended Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Amended Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51–102.

The preparation of the Amended Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Amended Consolidated Financial Statements. The preparation of the Amended Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of disclosure controls and procedures and internal control over financial reporting based on the framework and criteria established in the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2018. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

The Amended Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in all material respects in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Amended Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

On behalf of Hydro One's management:

**Paul Dobson**
Acting President and
Chief Executive Officer

**Christopher Lopez**
Acting Chief Financial Officer

# Report of Independent Registered Public Accounting Firm

**To the Shareholders and Board of Directors of Hydro One Limited**

## Opinion on the Amended Consolidated Financial Statements

We have audited the accompanying amended consolidated balance sheet of Hydro One Limited (the Company) as of December 31, 2018, the related amended consolidated statements of operations and comprehensive income, changes in equity, and cash flows for the year then ended, and the related amended notes (collectively, the amended consolidated financial statements). In our opinion, the amended consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended, in conformity with US generally accepted accounting principles.

## Basis for Opinion

These amended consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these amended consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the amended consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the amended consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the amended consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

KPMG LLP

**Chartered Professional Accountants, Licensed Public Accountants**

We have served as the Company's auditor since 2008

Toronto, Canada
March 25, 2019

# Independent Auditors' Report

**To the Shareholders and Board of Directors of Hydro One Limited**

We have audited the accompanying consolidated financial statements of Hydro One Limited, which comprise the consolidated balance sheet as at December 31, 2017, the consolidated statements of operations and comprehensive income, changes in equity, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

## Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

## Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2017, and its consolidated results of operations and its consolidated cash flows for the year then ended in accordance with US generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 25, 2019

# Amended Consolidated Statements of Operations and Comprehensive Income (Loss)

| Year ended December 31 (millions of Canadian dollars, except per share amounts) | 2018 | 2017 |
|---|---|---|
| **Revenues** | | |
| Distribution (includes $280 related party revenues; 2017 – $284) (Note 27) | **4,422** | 4,366 |
| Transmission (includes $1,617 related party revenues; 2017 – $1,523) (Note 27) | **1,686** | 1,578 |
| Other | **42** | 46 |
| | **6,150** | 5,990 |
| **Costs** | | |
| Purchased power (includes $1,648 related party costs; 2017 – $1,594) (Note 27) | **2,899** | 2,875 |
| Operation, maintenance and administration (Note 27) | **1,105** | 1,066 |
| Depreciation, amortization and asset removal costs (Note 5) | **837** | 817 |
| | **4,841** | 4,758 |
| **Income before financing charges and income taxes** | **1,309** | 1,232 |
| Financing charges (Note 6) | **459** | 439 |
| **Income before income taxes** | **850** | 793 |
| Income taxes (Note 7) | **915** | 111 |
| **Net income (loss)** | **(65)** | 682 |
| Other comprehensive income | **4** | 1 |
| **Comprehensive income (loss)** | **(61)** | 683 |
| **Net income (loss) attributable to:** | | |
| Noncontrolling interest (Note 26) | **6** | 6 |
| Preferred shareholders | **18** | 18 |
| Common shareholders | **(89)** | 658 |
| | **(65)** | 682 |
| **Comprehensive income attributable to:** | | |
| Noncontrolling interest (Note 26) | **6** | 6 |
| Preferred shareholders | **18** | 18 |
| Common shareholders | **(85)** | 659 |
| | **(61)** | 683 |
| **Earnings per common share** (Note 24) | | |
| Basic | **$ (0.15)** | $ 1.11 |
| Diluted | **$ (0.15)** | $ 1.10 |
| **Dividends per common share declared** (Note 23) | **$ 0.91** | $ 0.87 |

See accompanying notes to Amended Consolidated Financial Statements.

# Amended Consolidated Balance Sheets

| December 31 (millions of Canadian dollars) | 2018 | 2017 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | 483 | 25 |
| Accounts receivable (Note 8) | 628 | 636 |
| Due from related parties (Note 27) | 255 | 253 |
| Other current assets (Note 9) | 125 | 105 |
| | 1,491 | 1,019 |
| Property, plant and equipment (Note 10) | 20,687 | 19,947 |
| Other long-term assets: | | |
| Regulatory assets (Note 12) | 1,721 | 3,049 |
| Deferred income tax assets (Note 7) | 1,018 | 987 |
| Intangible assets (Note 11) | 410 | 369 |
| Goodwill | 325 | 325 |
| Other assets | 5 | 5 |
| | 3,479 | 4,735 |
| **Total assets** | 25,657 | 25,701 |
| **Liabilities** | | |
| Current liabilities: | | |
| Short-term notes payable (Note 15) | 1,252 | 926 |
| Long-term debt payable within one year (Notes 15, 17) | 731 | 752 |
| Accounts payable and other current liabilities (Note 13) | 956 | 905 |
| Due to related parties (Note 27) | 89 | 157 |
| | 3,028 | 2,740 |
| Long-term liabilities: | | |
| Long-term debt (includes $845 measured at fair value; 2017 – $541) (Notes 15, 17) | 9,978 | 9,315 |
| Convertible debentures (Notes 16, 17) | 489 | 487 |
| Regulatory liabilities (Note 12) | 326 | 128 |
| Deferred income tax liabilities (Note 7) | 58 | 71 |
| Other long-term liabilities (Note 14) | 2,135 | 2,707 |
| | 12,986 | 12,708 |
| **Total liabilities** | 16,014 | 15,448 |
| *Contingencies and Commitments* (Notes 29, 30) | | |
| *Subsequent Events* (Note 4, 16, 17, 32) | | |
| Noncontrolling interest subject to redemption (Note 26) | 21 | 22 |
| **Equity** | | |
| Common shares (Note 22) | 5,643 | 5,631 |
| Preferred shares (Note 22) | 418 | 418 |
| Additional paid-in capital (Note 25) | 56 | 49 |
| Retained earnings | 3,459 | 4,090 |
| Accumulated other comprehensive loss | (3) | (7) |
| Hydro One shareholders' equity | 9,573 | 10,181 |
| Noncontrolling interest (Note 26) | 49 | 50 |
| **Total equity** | 9,622 | 10,231 |
| | 25,657 | 25,701 |

See accompanying notes to Amended Consolidated Financial Statements.

On behalf of the Board of Directors:

**Tom Woods**
Chair

**William Sheffield**
Chair, Audit Committee

# Amended Consolidated Statements of Changes in Equity

| Year ended December 31, 2018 (millions of Canadian dollars) | Common Shares | Preferred Shares | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Hydro One Shareholders' Equity | Non-controlling Interest (Note 26) | Total Equity |
|---|---|---|---|---|---|---|---|---|
| January 1, 2018 | 5,631 | 418 | 49 | 4,090 | (7) | 10,181 | 50 | 10,231 |
| Net income (loss) | — | — | — | (71) | — | (71) | 4 | (67) |
| Other comprehensive income | — | — | — | — | 4 | 4 | — | 4 |
| Distributions to noncontrolling interest | — | — | — | — | — | — | (5) | (5) |
| Dividends on preferred shares | — | — | — | (18) | — | (18) | — | (18) |
| Dividends on common shares | — | — | — | (542) | — | (542) | — | (542) |
| Common shares issued | 12 | — | (12) | — | — | — | — | — |
| Stock-based compensation (Note 25) | — | — | 19 | — | — | 19 | — | 19 |
| **December 31, 2018** | 5,643 | 418 | 56 | 3,459 | (3) | 9,573 | 49 | 9,622 |

| Year ended December 31, 2017 (millions of Canadian dollars) | Common Shares | Preferred Shares | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Hydro One Shareholders' Equity | Non-controlling Interest (Note 26) | Total Equity |
|---|---|---|---|---|---|---|---|---|
| January 1, 2017 | 5,623 | 418 | 34 | 3,950 | (8) | 10,017 | 50 | 10,067 |
| Net income | — | — | — | 676 | — | 676 | 4 | 680 |
| Other comprehensive income | — | — | — | — | 1 | 1 | — | 1 |
| Distributions to noncontrolling interest | — | — | — | — | — | — | (4) | (4) |
| Dividends on preferred shares | — | — | — | (18) | — | (18) | — | (18) |
| Dividends on common shares | — | — | — | (518) | — | (518) | — | (518) |
| Common shares issued | 8 | — | (8) | — | — | — | — | — |
| Stock-based compensation (Note 25) | — | — | 23 | — | — | 23 | — | 23 |
| **December 31, 2017** | 5,631 | 418 | 49 | 4,090 | (7) | 10,181 | 50 | 10,231 |

See accompanying notes to Amended Consolidated Financial Statements.

# Amended Consolidated Statements of Cash Flows

| Year ended December 31 (millions of Canadian dollars) | 2018 | 2017 |
|---|---|---|
| **Operating activities** | | |
| Net income (loss) | (65) | 682 |
| Environmental expenditures | (22) | (24) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (Note 5) | 747 | 727 |
| Regulatory assets and liabilities | 35 | 112 |
| Deferred income taxes | 890 | 85 |
| Unrealized loss (gain) on foreign exchange contract | (25) | 3 |
| Other | 38 | 18 |
| Changes in non-cash balances related to operations (Note 28) | (23) | 113 |
| **Net cash from operating activities** | 1,575 | 1,716 |
| **Financing activities** | | |
| Long-term debt issued | 1,400 | — |
| Long-term debt repaid | (753) | (602) |
| Short-term notes issued | 4,242 | 3,795 |
| Short-term notes repaid | (3,916) | (3,338) |
| Convertible debentures issued (Note 16) | — | 513 |
| Dividends paid | (560) | (536) |
| Distributions paid to noncontrolling interest | (8) | (6) |
| Other (Note 16) | (6) | (27) |
| **Net cash from (used in) financing activities** | 399 | (201) |
| **Investing activities** | | |
| Capital expenditures (Note 28) | | |
| Property, plant and equipment | (1,418) | (1,467) |
| Intangible assets | (120) | (80) |
| Capital contributions received (Note 28) | 7 | 9 |
| Other | 15 | (2) |
| **Net cash used in investing activities** | (1,516) | (1,540) |
| **Net change in cash and cash equivalents** | 458 | (25) |
| Cash and cash equivalents, beginning of year | 25 | 50 |
| **Cash and cash equivalents, end of year** | 483 | 25 |

See accompanying notes to Amended Consolidated Financial Statements.

# Notes to Amended Consolidated Financial Statements

For the years ended December 31, 2018 and 2017

## 1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2018, the Province held approximately 47.4% (2017 – 47.4%) of the common shares of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

### Rate Setting

The Company's transmission business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM), as well as an approximately 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation (SON) in respect of the Bruce-to-Milton transmission line. Hydro One's distribution business consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remote Communities).

#### Ontario Energy Board (OEB) March 7, 2019 Decisions and Amended Consolidated Financial Statements

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements dated September 28, 2017 (Original Decision) with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange.

The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under United States (US) Generally Accepted Accounting Principles (GAAP) and as such the Company is required to update the consolidated financial statements previously issued on February 20, 2019, to reflect the subsequent event in connection with filing its annual report on Form 40-F with the US Securities and Exchange Commission, so that they reflect events to the date of approval of the Form 40-F. As a result, the financial impact of this OEB decision has been reflected in these amended consolidated financial statements, as more fully discussed in Note 12 – Regulatory Assets and Liabilities.

#### Transmission

In December 2017, the OEB approved Hydro One Networks' 2018 rates revenue requirement of $1,511 million. See Note 12 – Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On May 10, 2018, the OEB issued its decision and rate order on B2M LP's 2018 transmission application reflecting revenue requirement of $36 million, effective January 1, 2018.

HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB Mergers Acquisitions Amalgamations and Divestitures (MAAD) decision dated October 13, 2016. In September 2017, the OEB issued its decision and Order on HOSSM's 2017 transmission rate application, denying the requested revenue requirement. HOSSM's 2016 approved revenue requirement of $41 million remained in effect for 2017 and 2018.

#### Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. The requested revenue requirements, updated in June 2018, are $1,514 million for 2018, $1,561 million for 2019, $1,607 million for 2020, $1,681 million for 2021, and $1,722 million for 2022. The OEB decision was received on March 7, 2019. See Note 32(D) – Subsequent Events – OEB Regulatory Decisions.

On November 17, 2017, Hydro One filed with the OEB a request for 2018 interim rates based on 2017 OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim 2018 rates based on 2017 OEB- approved rates with no adjustments.

On August 28, 2017, Hydro One Remote Communities filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On March 19, 2018, the OEB approved the settlement agreement related to the 2018 rates application reached by Hydro One Remote Communities and the intervenors in the rate proceeding. On March 26, 2018, a draft rate order was filed with the OEB for 2018 rates. The OEB approved the draft rate order on April 12, 2018, and the new rates were implemented effective May 1, 2018.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Consolidation

These Amended Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

### Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with US GAAP and in Canadian dollars.

### Use of Management Estimates

The preparation of financial statements 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, expenses, gains and losses during the reporting periods.

Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

## Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses 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 an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a Type I subsequent event.

## Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

## Revenue Recognition

The Company adopted Accounting Standard Codification (ASC) 606 – *Revenue from Contracts with Customers* on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Company's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

### Nature of Revenues

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTR) and the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTR is based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

## Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

## Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

## Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

**Deferred Income Taxes**

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

As approved by the regulator, the Company's Canadian subsidiaries recover income tax expense in customer rates based on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the regulator. The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

## Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

## Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

**Transmission**

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

**Distribution**

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

**Communication**

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

**Administration and Service**

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

**Easements**

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

## Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

## Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

## Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

### Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

| | Average Service Life | Rate Range | Rate Average |
|---|---|---|---|
| Property, plant and equipment: | | | |
| Transmission | 55 years | 1% – 3% | 2% |
| Distribution | 46 years | 1% – 7% | 2% |
| Communication | 16 years | 1% – 15% | 6% |
| Administration and service | 20 years | 1% – 20% | 6% |
| Intangible assets | 10 years | 10% | 10% |

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

### Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2018, the Company has concluded that goodwill was not impaired at December 31, 2018.

### Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2018 and 2017, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

### Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

### Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

### Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 – Fair Value of Financial Instruments and Risk Management.

### Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2018 or 2017.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

## Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the Consolidated Statements of Operations and Comprehensive Income.

### Defined Benefit Pension

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded PBO for its pension plan. Defined benefit pension costs are attributed to labour costs and a portion directly related to acquisition and development of capital assets not exceeding the service cost component of accrual basis defined benefit pension costs is capitalized as part of the cost of property, plant and equipment and intangible assets. The remaining defined benefit pension costs are charged to results of operations (OM&A costs).

### Post-retirement and Post-employment Benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets for service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

## Stock-Based Compensation

### Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

**Deferred Share Unit (DSU) Plans**

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

**Long-term Incentive Plan (LTIP)**

The Company measures the awards issued under its LTIP, at fair value based on the grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

### Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

### Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

### Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

## 3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

### Recently Adopted Accounting Guidance

| Guidance | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| ASC 606 | May 2014 – November 2017 | ASC 606 *Revenue from Contracts with Customers* replaced ASC 605 *Revenue Recognition*. ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. | January 1, 2018 | On January 1, 2018, Hydro One adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption. |
| ASU 2017-07 | March 2017 | Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable. | January 1, 2018 | Hydro One applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 – Significant Accounting Policies and Note 12 – Regulatory Assets and Liabilities. |

### Recently Issued Accounting Guidance Not Yet Adopted

| Guidance | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| 2016-02<br>2018-01<br>2018-10<br>2018-11<br>2018-20 | February 2016 – December 2018 | Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties. | January 1, 2019 | Hydro One reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to Hydro One's financial statements will be the recognition of approximately $27 million Right-of-Use (ROU) assets and corresponding lease obligations on the Consolidated Balance Sheet. The ROU assets and lease obligations represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to the Company's incremental borrowing rate. |

| Guidance | Date issued | Description | Effective date | Impact on Hydro One |
|---|---|---|---|---|
| 2018-07 | June 2018 | Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees. | January 1, 2019 | No impact upon adoption |
| 2018-13 | August 2018 | Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes. | January 1, 2020 | Under assessment |
| 2018-14 | August 2018 | Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes. | January 1, 2021 | Under assessment |
| 2018-15 | August 2018 | The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment. | January 1, 2020 | Under assessment |

## 4. BUSINESS COMBINATION

### Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger was subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

The costs related to the acquisition totalling $69 million (2017 – $42 million) have been expensed through the consolidated statements of operations. These costs, net of unrealized gains on the foreign exchange contract of $25 million in the year ended December 31, 2018 and a loss of $3 million in the year ended December 31, 2017, resulted in net costs of $44 million and $45 million, respectively being included in earnings.

On December 5, 2018, the Washington Utilities and Transportation Commission (Washington UTC) issued an order denying the Merger. On December 17, 2018, Hydro One filed a petition requesting the Washington UTC to reconsider its December 5, 2018 order denying the Merger. On January 3, 2018, the Idaho Public Utilities Commission denied Hydro One's application to acquire Avista Corporation. On January 8, 2019, the Washington UTC issued a notice of denial of Hydro One's petition for reconsideration of Washington UTC's December 5, 2018 order denying the Merger. On January 14, 2019, the Oregon Public Utility Commission issued a notice of abeyance until Hydro One and Avista Corporation have sought a reversal of the two denial decisions.

On January 23, 2019, Hydro One and Avista Corporation announced that the companies have mutually agreed to terminate the Merger agreement. As a result of the termination of the Merger agreement, on January 24, 2019, Hydro One paid a US$103 million termination fee to Avista Corporation as required by the Merger agreement. On January 24, 2019, the Company cancelled the $1.0 billion non-revolving equity bridge credit facility and on January 25, 2019, Hydro One terminated the US$2.6 billion non-revolving debt bridge credit facility (Acquisition Credit Facilities). No amounts have been drawn on the Acquisition Credit Facilities. On February 1, 2019, Hydro One entered into a credit agreement for a $170 million unsecured demand operating credit facility (Demand Facility) for the purpose of funding the payment of the termination fee and other Merger related costs. On February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts $513 million ($333 per $1,000 principal amount) plus accrued and unpaid interest of $7 million. The redemption of the convertible debentures was paid with cash on hand. As a result of the termination of the Merger agreement, no payment is due or receivable by Hydro One on the foreign exchange contract.

The following amounts related to the termination of the Merger agreement will be recorded by the Company in its 2019 first quarter financial statements:

- $138 million OM&A costs for payment of the US$103 million termination fee;
- $22 million financing charges, due to revaluation of the foreign-exchange contract to $nil and reversal of previously recorded gains;
- repayment of $513 million convertible debentures and related interest of $7 million; and
- $24 million financing charges, due to derecognition of the deferred financing costs related to convertible debentures.

See Note 16 – Convertible Debentures and Note 17 – Fair Value of Financial Instruments and Risk Management for details of the convertible debentures and the foreign exchange contract, respectively.

### Orillia Power Purchase Agreement

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments and regulatory approval by the OEB. In September 2016, Hydro One filed an application with the OEB to acquire Orillia Power, which was denied by the OEB on April 12, 2018. On September 26, 2018, Hydro One filed a new application with the OEB for approval to acquire Orillia Power.

### Peterborough Distribution Purchase Agreement

On July 31, 2018, Hydro One reached an agreement to acquire the business and distribution assets of Peterborough Distribution Inc. (Peterborough Distribution), an electricity distribution company located in east central Ontario, from the City of Peterborough for approximately $105 million. The acquisition is conditional upon the satisfaction of customary closing conditions and approval by the OEB and the Competition Bureau. On October 12, 2018, the Company filed an application with the OEB for approval of the acquisition. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's position.

## 5. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Depreciation of property, plant and equipment | 654 | 641 |
| Amortization of intangible assets | 71 | 62 |
| Amortization of regulatory assets | 22 | 24 |
| Depreciation and amortization | 747 | 727 |
| Asset removal costs | 90 | 90 |
| | 837 | 817 |

## 6. FINANCING CHARGES

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Interest on long-term debt | 447 | 450 |
| Interest on convertible debentures | 62 | 24 |
| Interest on short-term notes | 14 | 6 |
| Unrealized loss (gain) on foreign exchange contract (Note 17) | (25) | 3 |
| Other | 21 | 14 |
| Less: Interest capitalized on construction and development in progress | (53) | (56) |
| Interest earned on cash and cash equivalents | (7) | (2) |
| | 459 | 439 |

## 7. INCOME TAXES

As a rate regulated utility company, the Company's effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Income before income taxes | 850 | 793 |
| Income taxes at statutory rate of 26.5% (2017 – 26.5%) | 225 | 210 |
| Increase (decrease) resulting from: | | |
| Net temporary differences recoverable in future rates charged to customers: | | |
| Capital cost allowance in excess of depreciation and amortization | (68) | (55) |
| Overheads capitalized for accounting but deducted for tax purposes | (20) | (17) |
| Interest capitalized for accounting but deducted for tax purposes | (14) | (15) |
| Pension contributions in excess of pension expense | (11) | (13) |
| Environmental expenditures | (6) | (6) |
| Other | (9) | 3 |
| Net temporary differences | (128) | (103) |
| Net permanent differences | 1 | 4 |
| Write-off of unregulated deferred income tax asset (Notes 12, 32) | 885 | — |
| Non-recurring tax recovery relating to deferred tax asset sharing[1] (Notes 12, 32) | (68) | — |
| Total income taxes | 915 | 111 |
| Effective income tax rate | 107.6% | 14.0% |

1 This represents the reversal of cumulative deferred tax expenses recorded in 2017 and 2018 relating to temporary differences that are now being allocated to ratepayers. For rate-setting purposes, the deferred income tax expenses or recovery relating to temporary differences that will be included in the rate-setting process are recorded as regulatory assets and liabilities on the balance sheet.

The major components of income tax expense are as follows:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Current income taxes | 25 | 26 |
| Deferred income taxes | 890 | 85 |
| Total income taxes | 915 | 111 |

## Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2018 and 2017, deferred income tax assets and liabilities consisted of the following:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| **Deferred income tax assets** | | |
| Post-retirement and post-employment benefits expense in excess of cash payments | **526** | 561 |
| Non-capital losses | **302** | 255 |
| Non-depreciable capital property | **271** | 271 |
| Pension obligations | **197** | 354 |
| Investment in subsidiaries | **86** | 84 |
| Tax credit carryforwards | **71** | 49 |
| Environmental expenditures | **59** | 71 |
| Depreciation and amortization in excess of capital cost allowance | **20** | 125 |
| Other | **24** | 23 |
| | **1,556** | 1,793 |
| Less: valuation allowance | **(366)** | (364) |
| Total deferred income tax assets | **1,190** | 1,429 |
| **Deferred income tax liabilities** | | |
| Capital cost allowance in excess of depreciation and amortization | **9** | 75 |
| Regulatory amounts that are not recognized for tax purposes | **188** | 411 |
| Goodwill | **10** | 10 |
| Other | **23** | 17 |
| Total deferred income tax liabilities | **230** | 513 |
| Net deferred income tax assets | **960** | 916 |

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Long-term: | | |
| Deferred income tax assets | **1,018** | 987 |
| Deferred income tax liabilities | **(58)** | (71) |
| Net deferred income tax assets | **960** | 916 |

The valuation allowance for deferred tax assets as at December 31, 2018 was $366 million (2017 – $364 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2018 and 2017, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

| Year of expiry (millions of dollars) | 2018 | 2017 |
|---|---|---|
| 2034 | **2** | 2 |
| 2035 | **221** | 222 |
| 2036 | **551** | 560 |
| 2037 | **172** | 175 |
| 2038 | **192** | – |
| Total losses | **1,138** | 959 |

## 8. ACCOUNTS RECEIVABLE

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Accounts receivable – billed | 292 | 298 |
| Accounts receivable – unbilled | 357 | 367 |
| Accounts receivable, gross | 649 | 665 |
| Allowance for doubtful accounts | (21) | (29) |
| Accounts receivable, net | 628 | 636 |

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Allowance for doubtful accounts – beginning | (29) | (35) |
| Write-offs | 25 | 25 |
| Additions to allowance for doubtful accounts | (17) | (19) |
| Allowance for doubtful accounts – ending | (21) | (29) |

## 9. OTHER CURRENT ASSETS

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Regulatory assets (Note 12) | 42 | 46 |
| Prepaid expenses and other assets | 41 | 41 |
| Derivative instrument – foreign exchange contract (Note 17) | 22 | — |
| Materials and supplies | 20 | 18 |
| | 125 | 105 |

## 10. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2018 (millions of dollars) | Property, Plant and Equipment | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Transmission | 16,559 | 5,449 | 766 | 11,876 |
| Distribution | 10,580 | 3,561 | 75 | 7,094 |
| Communication | 1,306 | 922 | 48 | 432 |
| Administration and service | 1,548 | 893 | 58 | 713 |
| Easements | 647 | 75 | — | 572 |
| | 30,640 | 10,900 | 947 | 20,687 |

| December 31, 2017 (millions of dollars) | Property, Plant and Equipment | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Transmission | 15,509 | 5,162 | 989 | 11,336 |
| Distribution | 10,213 | 3,513 | 149 | 6,849 |
| Communication | 1,266 | 853 | 31 | 444 |
| Administration and service | 1,561 | 857 | 46 | 750 |
| Easements | 638 | 70 | — | 568 |
| | 29,187 | 10,455 | 1,215 | 19,947 |

Financing charges capitalized on property, plant and equipment under construction were $51 million in 2018 (2017 – $54 million).

## 11. INTANGIBLE ASSETS

| December 31, 2018 (millions of dollars) | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 790 | 440 | 60 | 410 |
| Other | 5 | 5 | — | — |
| | 795 | 445 | 60 | 410 |

| December 31, 2017 (millions of dollars) | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 698 | 370 | 41 | 369 |
| Other | 5 | 5 | — | — |
| | 703 | 375 | 41 | 369 |

Financing charges capitalized to intangible assets under development were $2 million in 2018 (2017 – $2 million). The estimated annual amortization expense for intangible assets is as follows: 2019 – $67 million; 2020 – $50 million; 2021 – $48 million; 2022 – $46 million; and 2023 – $35 million.

## 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| **Regulatory assets:** | | |
| Deferred income tax regulatory asset | 908 | 1,762 |
| Pension benefit regulatory asset | 547 | 981 |
| Environmental | 165 | 196 |
| Foregone revenue deferral | — | 23 |
| Stock-based compensation | 43 | 40 |
| Post-retirement and post-employment benefits non-service cost | 39 | — |
| Debt premium | 22 | 27 |
| Distribution system code exemption | 10 | 10 |
| B2M LP start-up costs | 2 | 4 |
| Post-retirement and post-employment benefits | — | 36 |
| Other | 27 | 16 |
| Total regulatory assets | 1,763 | 3,095 |
| Less: current portion | (42) | (46) |
| | 1,721 | 3,049 |
| **Regulatory liabilities:** | | |
| Post-retirement and post-employment benefits | 130 | — |
| Pension cost differential | 55 | 23 |
| Green Energy expenditure variance | 52 | 60 |
| Retail settlement variance account | 39 | — |
| External revenue variance | 26 | 46 |
| 2015-2017 rate rider | 6 | 6 |
| Deferred income tax regulatory liability | 86 | 5 |
| Conservation and Demand Management (CDM) deferral variance | — | 28 |
| Other | 23 | 17 |
| Total regulatory liabilities | 417 | 185 |
| Less: current portion | (91) | (57) |
| | 326 | 128 |

### Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2018 income tax expense would have been lower by approximately $686 million (2017 – higher by $113 million).

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision). In its Original Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a decision and order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. On August 31, 2018, the OEB granted the Motion and returned the portion of the Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, on March 7, 2019, the OEB issued its reconsideration decision and concluded that their Original Decision was reasonable and should be upheld. Also, on March 7, 2019 the OEB issued its decision for Hydro One Networks' 2018–2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. As a result of this subsequent event that requires adjustment in the 2018 financial statements, the Company has recognized an impairment charge of Hydro One Networks' distribution deferred income tax regulatory asset of $474 million and Hydro One Networks' transmission deferred income tax regulatory asset of $558 million, an increase in deferred income tax regulatory liability of $81 million, and a decrease in the foregone revenue deferral regulatory asset of $68 million. After recognition of the related $314 million deferred tax asset, the Company has recorded an $867 million one-time decrease in net income as a reversal of revenues of $68 million, and charge to deferred tax expense of $799 million. Notwithstanding the recognition of the effects of the decision in the financial statements, the Company is currently considering its options under the Appeal.

### Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, OCI would have been higher by $435 million (2017 – lower by $80 million) and OM&A expenses would have been higher by $1 million (2017 – $1 million).

### Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2018, the environmental regulatory asset decreased by $15 million (2017 – increased by $8 million) to reflect related changes in the Company's PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the xi and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been lower by $15 million (2017 – higher by $8 million). In addition, 2018 amortization expense would have been lower by $22 million (2017 – $24 million), and 2018 financing charges would have been higher by $6 million (2017 – $8 million).

### Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts were returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. As part of its May 2018 decision, the OEB also directed B2M LP to record in this account any revenue collected in 2018 in excess of the final approved 2018 B2M LP revenue requirement.

### Stock-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been higher by $1 million (2017 – $8 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

### Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory liability, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2018 OCI would have been higher by $166 million (2017 – $207 million).

### Post-Retirement and Post-Employment Benefits – Non-Service Cost

Hydro One applied to the OEB for a regulatory asset to record the components other than service costs relating to its post-retirement and post-employment benefits that would have previously been capitalized to property, plant and equipment and intangible assets prior to adoption of ASU 2017-07. In May 2018, the OEB approved the regulatory asset for Hydro One Networks' Transmission Business. It is expected that the regulatory asset application for Hydro One Networks' Distribution business will be considered as part of Hydro One Networks' application for 2018-2022 distribution rates, OEB approval of which is currently pending. Hydro One has recorded the components other than service costs relating to its post-retirement and post-employment benefits that would have been capitalized to property, plant and equipment and intangible assets, in the Post-Retirement and Post-Employment Benefits Non-Service Cost Regulatory Asset.

### Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP – Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

### Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In 2015, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2018 or 2017. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

### B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

### Pension Cost Differential

A pension cost differential account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost differential account as at December 31, 2015, including accrued interest, which was recovered over a two-year period ended December 31, 2018. The distribution business portion of the balance as at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application. In the absence of rate-regulated accounting, 2018 revenue would have been higher by $29 million (2017 – $24 million).

### Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

### Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The balance as at December 31, 2014, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

### External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which was returned to customers over a two-year period ended December 31, 2018. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

### 2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application and has not been requested in the current distribution rate application.

### CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual CDM and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account related to the actual 2013 and 2014 CDM and demand response results on load forecasts, which are inputs in the UTR, compared to the amounts included in 2013 and 2014 revenue requirements, respectively. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and returned to customers over a 2-year period ended December 31, 2018.

## 13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Accounts payable | 179 | 177 |
| Accrued liabilities | 590 | 572 |
| Accrued interest | 96 | 99 |
| Regulatory liabilities (Note 12) | 91 | 57 |
| | 956 | 905 |

## 14. OTHER LONG-TERM LIABILITIES

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Post-retirement and post-employment benefit liability (Note 19) | 1,417 | 1,519 |
| Pension benefit liability (Note 19) | 547 | 981 |
| Environmental liabilities (Note 20) | 139 | 168 |
| Long-term accounts payable | 12 | 13 |
| Asset retirement obligations (Note 21) | 10 | 9 |
| Other liabilities | 10 | 17 |
| | 2,135 | 2,707 |

## 15. DEBT AND CREDIT AGREEMENTS

### Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At December 31, 2018, Hydro One's consolidated committed, unsecured and undrawn credit facilities (Operating Credit Facilities) totalling $2,550 million consisted of the following:

| (millions of dollars) | Maturity | Total Amount | Amount Drawn |
|---|---|---|---|
| **Hydro One Inc.** | | | |
| Revolving standby credit facility | June 2022 | 2,300 | — |
| **Hydro One** | | | |
| Five-year senior, revolving term credit facility | November 2021 | 250 | — |
| Total | | 2,550 | — |

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

### Subsidiary Debt Guarantee

Hydro One Holdings Limited (HOHL) is an indirect wholly-owned subsidiary of Hydro One that may offer and sell debt securities. Any debt securities issued by HOHL are fully and unconditionally guaranteed by the Company. At December 31, 2018, no debt securities have been issued by HOHL.

## Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2018 and 2017:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| 2.78% Series 28 notes due 2018 | — | 750 |
| Floating-rate Series 31 notes due 2019[1] | 228 | 228 |
| 1.48% Series 37 notes due 2019[2] | 500 | 500 |
| 4.40% Series 20 notes due 2020 | 300 | 300 |
| 1.62% Series 33 notes due 2020[2] | 350 | 350 |
| 1.84% Series 34 notes due 2021 | 500 | 500 |
| 2.57% Series 39 notes due 2021[2] | 300 | — |
| 3.20% Series 25 notes due 2022 | 600 | 600 |
| 2.97% Series 40 notes due 2025 | 350 | — |
| 2.77% Series 35 notes due 2026 | 500 | 500 |
| 7.35% Debentures due 2030 | 400 | 400 |
| 6.93% Series 2 notes due 2032 | 500 | 500 |
| 6.35% Series 4 notes due 2034 | 385 | 385 |
| 5.36% Series 9 notes due 2036 | 600 | 600 |
| 4.89% Series 12 notes due 2037 | 400 | 400 |
| 6.03% Series 17 notes due 2039 | 300 | 300 |
| 5.49% Series 18 notes due 2040 | 500 | 500 |
| 4.39% Series 23 notes due 2041 | 300 | 300 |
| 6.59% Series 5 notes due 2043 | 315 | 315 |
| 4.59% Series 29 notes due 2043 | 435 | 435 |
| 4.17% Series 32 notes due 2044 | 350 | 350 |
| 5.00% Series 11 notes due 2046 | 325 | 325 |
| 3.91% Series 36 notes due 2046 | 350 | 350 |
| 3.72% Series 38 notes due 2047 | 450 | 450 |
| 3.63% Series 41 notes due 2049 | 750 | — |
| 4.00% Series 24 notes due 2051 | 225 | 225 |
| 3.79% Series 26 notes due 2062 | 310 | 310 |
| 4.29% Series 30 notes due 2064 | 50 | 50 |
| Hydro One Inc. long-term debt (a) | 10,573 | 9,923 |
| 6.6% Senior Secured Bonds due 2023 (Principal amount – $107 million) | 129 | 136 |
| 4.6% Note Payable due 2023 (Principal amount – $36 million) | 39 | 40 |
| HOSSM long-term debt (b) | 168 | 176 |
| | 10,741 | 10,099 |
| Add: Net unamortized debt premiums | 13 | 14 |
| Add: Unrealized mark-to-market gain[2] | (5) | (9) |
| Less: Deferred debt issuance costs | (40) | (37) |
| Total long-term debt | 10,709 | 10,067 |

1 The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

2 The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020, $500 million Series 37 notes due 2019, and $300 million Series 39 notes due 2021. The unrealized mark-to-market net gain is offset by a $5 million (2017 – $9 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. long-term debt

At December 31, 2018, long-term debt of $10,573 million (2017 – $9,923 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in March 2018 is $4.0 billion. At December 31, 2018, $2.6 billion remained available for issuance until April 2020.

In 2018, Hydro One Inc. issued long-term debt totalling $1.4 billion (2017 – $nil) and repaid long-term debt of $750 million (2017 – $600 million) under its MTN Program.

(b) HOSSM long-term debt

At December 31, 2018, long-term debt of $168 million (2017 – $176 million), with a principal amount of $143 million (2017 – $146 million) was issued by HOSSM. In 2018, no long-term debt was issued (2017 – $nil), and $3 million (2017 – $2 million) of long-term debt was repaid.

The total long-term debt is presented on the consolidated balance sheets as follows:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Current liabilities: | | |
| Long-term debt payable within one year | **731** | 752 |
| Long-term liabilities: | | |
| Long-term debt | **9,978** | 9,315 |
| Total long-term debt | **10,709** | 10,067 |

### Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

| Years | Long-term Debt Principal Repayments (millions of dollars) | Interest Payments (millions of dollars) | Weighted Average Interest Rate (%) |
|---|---|---|---|
| 2019 | 731 | 448 | 1.9 |
| 2020 | 653 | 429 | 2.9 |
| 2021 | 803 | 411 | 2.1 |
| 2022 | 603 | 393 | 3.2 |
| 2023 | 131 | 379 | 6.1 |
| | 2,921 | 2,060 | 2.6 |
| 2024-2028 | 850 | 1,806 | 2.9 |
| 2029 and thereafter | 6,945 | 4,315 | 5.1 |
| | 10,716 | 8,181 | 4.2 |

## 16. CONVERTIBLE DEBENTURES

As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), on February 8, 2019, Hydro One redeemed the Convertible Debentures and paid the holders of the instalment receipts $513 million ($333 per $1,000 principal amount) plus accrued and unpaid interest of $7 million.

The following table presents the change in convertible debentures during the years ended December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Carrying value – beginning | **487** | — |
| Receipt of Initial Instalment, net of deferred financing costs | **—** | 486 |
| Amortization of deferred financing costs | **2** | 1 |
| Carrying value – ending | **489** | 487 |
| Face value – ending | **513** | 513 |

On August 9, 2017, in connection with the Merger (see Note 4 – Business Combinations), the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) was payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred financing costs of $27 million, which were being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures maturity date was September 30, 2027. A coupon rate of 4% was paid on the $1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translated into an effective annual yield of 12%. After the Final Instalment Date, the interest rate would be 0%. The interest expense recorded in 2018 was $62 million (2017 – $24 million).

At the option of the holders and provided that payment of the Final Instalment had been made, each Convertible Debenture would be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures.

The conversion feature met the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million at the date of issuance. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized, and as a result of the subsequent redemption of the Convertible Debentures on February 8, 2019, there will be no recognition.

## 17. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

### Non-Derivative Financial Assets and Liabilities

At December 31, 2018 and 2017, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

### Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2018 and 2017 are as follows:

| December 31 (millions of dollars) | 2018 Carrying Value | 2018 Fair Value | 2017 Carrying Value | 2017 Fair Value |
|---|---|---|---|---|
| Long-term debt measured at fair value: | | | | |
| $50 million of MTN Series 33 notes | **49** | **49** | 49 | 49 |
| $500 million MTN Series 37 notes | **495** | **495** | 492 | 492 |
| $300 million MTN Series 39 notes | **301** | **301** | — | — |
| Other notes and debentures | **9,864** | **10,820** | 9,526 | 11,027 |
| Long-term debt, including current portion | **10,709** | **11,665** | 10,067 | 11,568 |

### Fair Value Measurements of Derivative Instruments

At December 31, 2018, Hydro One Inc. had interest-rate swaps with a total notional amount of $850 million (2017 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 8% (2017 – 6%) of its total long-term debt. At December 31, 2018, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt;
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt; and
- a $300 million fixed-to-floating interest-rate swap agreement to convert the $300 million MTN Series 39 notes maturing June 25, 2021 into three-month variable rate debt.

At December 31, 2018 and 2017, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract (foreign exchange contract) to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract was contingent on the Company closing the proposed Merger (see Note 4 – Business Combinations) and was intended to mitigate the foreign currency risk related to the portion of the Merger purchase price financed with the issuance of Convertible Debentures. This contract is an economic hedge and does not qualify for hedge accounting. It has been accounted for as an undesignated contract with changes in fair value being recorded in earnings as they occur. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), no payment is due or payable by Hydro One on the foreign exchange contract.

### Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

| December 31, 2018 (millions of dollars) | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Cash and cash equivalents | 483 | 483 | 483 | — | — |
| Derivative instrument | | | | | |
| Foreign exchange contract | 22 | 22 | — | — | 22 |
| | 505 | 505 | 483 | — | 22 |
| **Liabilities:** | | | | | |
| Short-term notes payable | 1,252 | 1,252 | 1,252 | — | — |
| Long-term debt, including current portion | 10,709 | 11,665 | — | 11,665 | — |
| Convertible debentures | 489 | 491 | 491 | — | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 5 | 5 | — | 5 | — |
| | 12,455 | 13,413 | 1,743 | 11,670 | — |

| December 31, 2017 (millions of dollars) | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Assets:** | | | | | |
| Cash and cash equivalents | 25 | 25 | 25 | — | — |
| | 25 | 25 | 25 | — | — |
| **Liabilities:** | | | | | |
| Short-term notes payable | 926 | 926 | 926 | — | — |
| Long-term debt, including current portion | 10,067 | 11,568 | — | 11,568 | — |
| Convertible debentures | 487 | 574 | 574 | — | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 9 | 9 | — | 9 | — |
| Foreign exchange contract | 3 | 3 | — | — | 3 |
| | 11,492 | 13,080 | 1,500 | 11,577 | 3 |

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on December 31, 2018, as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves, probability of closing the Merger, and the contract settlement date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probability of closing the Merger and the contract settlement date.

**Changes in the Fair Value of Financial Instruments Classified in Level 3**

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2018 and 2017.

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Fair value of asset (liability) – beginning | (3) | — |
| Unrealized gain (loss) on foreign exchange contract included in financing charges | 25 | (3) |
| Fair value of asset (liability) – ending | 22 | (3) |

There were no transfers between any of the fair value levels during the years ended December 31, 2018 or 2017.

## Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

### Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2018 and 2017.

The Company was exposed to foreign exchange fluctuations as a result of entering into a foreign exchange contract. This agreement was intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), no payment is due or receivable by Hydro One on the foreign exchange contract.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2018 and 2017 was not material.

### Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At December 31, 2018 and 2017, there was no material accounts receivable balance due from any single customer.

At December 31, 2018, the Company's provision for bad debts was $21 million (2017 – $29 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2018, approximately 5% (2017 – 5%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2018 and 2017, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2018, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

**Liquidity Risk**

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term operating liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the Operating Credit Facilities. The short-term liquidity under the Commercial Paper Program, Operating Credit Facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

On June 18, 2018, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada to replace the universal base shelf prospectus that expired on April 30, 2018. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to $4.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on July 18, 2020. On November 23, 2018, HOHL, an indirect wholly-owned subsidiary of Hydro One, filed a short form base shelf prospectus (US Debt Shelf Prospectus) with securities regulatory authorities in Canada and the US for the purposes of, but not limited to, funding a portion of the cash purchase price of the Merger. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US$3.0 billion of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending on December 23, 2020. At December 31, 2018, no securities have been issued under the Universal Base Shelf Prospectus or the US Debt Shelf Prospectus.

## 18. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2018 and 2017, the Company's capital structure was as follows:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Long-term debt payable within one year | **731** | 752 |
| Short-term notes payable | **1,252** | 926 |
| Less: cash and cash equivalents | **(483)** | (25) |
| | **1,500** | 1,653 |
| Long-term debt | **9,978** | 9,315 |
| Convertible debentures | **489** | 487 |
| Preferred shares | **418** | 418 |
| Common shares | **5,643** | 5,631 |
| Retained earnings | **3,459** | 4,090 |
| **Total capital** | **21,487** | 21,594 |

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. Long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2018, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

## 19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

### DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. Hydro One contributions to the DC Plan for the year ended December 31, 2018 were $1 million (2017 – $1 million).

### Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. Annual Pension Plan contributions for 2018 were $75 million (2017 – $87 million). Estimated annual Pension Plan contributions for the years 2019, 2020, 2021, 2022, 2023 and 2024 are approximately $78 million, $77 million, $78 million, $79 million, $81 million and $83 million, respectively. The most recent actuarial valuation was performed effective December 31, 2017, and the next actuarial valuation will be performed no later than effective December 31, 2020. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

The following tables provide the components of the unfunded status of the Company's Plans at December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | Pension Benefits 2018 | Pension Benefits 2017 | Post-Retirement and Post-Employment Benefits 2018 | Post-Retirement and Post-Employment Benefits 2017 |
|---|---|---|---|---|
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation, beginning of year | **8,258** | 7,774 | **1,565** | 1,690 |
| Current service cost | **176** | 147 | **50** | 49 |
| Employee contributions | **52** | 49 | **—** | — |
| Interest cost | **282** | 304 | **54** | 67 |
| Benefits paid | **(362)** | (368) | **(49)** | (44) |
| Net actuarial loss (gain) | **(654)** | 352 | **(158)** | (197) |
| Recognition of prior service | **—** | — | **3** | — |
| Projected benefit obligation, end of year | **7,752** | 8,258 | **1,465** | 1,565 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, beginning of year | **7,277** | 6,874 | **—** | — |
| Actual return on plan assets | **190** | 662 | **—** | — |
| Benefits paid | **(362)** | (368) | **(49)** | (34) |
| Employer contributions | **75** | 87 | **49** | 34 |
| Employee contributions | **52** | 49 | **—** | — |
| Administrative expenses | **(27)** | (27) | **—** | — |
| Fair value of plan assets, end of year | **7,205** | 7,277 | **—** | — |
| Unfunded status | **547** | 981 | **1,465** | 1,565 |

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

| December 31 (millions of dollars) | Pension Benefits 2018 | 2017 | Post-Retirement and Post-Employment Benefits 2018 | 2017 |
|---|---|---|---|---|
| Other assets[1] | **3** | 1 | **—** | — |
| Accrued liabilities | **—** | — | **55** | 53 |
| Pension benefit liability | **547** | 981 | **—** | — |
| Post-retirement and post-employment benefit liability[2] | **—** | — | **1,417** | 1,519 |
| Net unfunded status | **544** | 980 | **1,472** | 1,572 |

1 Represents the funded status of HOSSM defined benefit pension plan.

2 Includes $7 million (2017 – $7 million) relating to HOSSM post-employment benefit plans.

The funded or unfunded status of the Plans refers to the difference between the fair value of plan assets and the PBO for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the PBO, accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| PBO | **7,752** | 8,258 |
| ABO | **7,144** | 7,614 |
| Fair value of plan assets | **7,205** | 7,277 |

On an ABO basis, the Pension Plan was funded at 101% at December 31, 2018 (2017 – 96%). On a PBO basis, the Pension Plan was funded at 93% at December 31, 2018 (2017 – 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

## Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2018 and 2017 for the Pension Plan:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Current service cost | **176** | 147 |
| Interest cost | **282** | 304 |
| Expected return on plan assets, net of expenses | **(467)** | (442) |
| Amortization of actuarial losses | **84** | 79 |
| Net periodic benefit costs | **75** | 88 |
| Charged to results of operations[1] | **32** | 39 |

1 The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2018, pension costs of $75 million (2017 – $87 million) were attributed to labour, of which $32 million (2017 – $39 million) was charged to operations, and $43 million (2017 – $48 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2018 and 2017 for the post-retirement and post-employment benefit plans:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Current service cost | **50** | 49 |
| Interest cost | **53** | 67 |
| Amortization of actuarial losses | **15** | 16 |
| Recognition of prior service | **3** | — |
| Net periodic benefit costs | **121** | 132 |
| Charged to results of operations | **52** | 59 |

## Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2018 and 2017:

| | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| Year ended December 31 | **2018** | 2017 | **2018** | 2017 |
| **Significant assumptions:** | | | | |
| Weighted average discount rate | **3.90%** | 3.40% | **4.00%** | 3.40% |
| Rate of compensation scale escalation (long-term) | **2.50%** | 2.50% | **2.50%** | 2.50% |
| Rate of cost of living increase | **2.00%** | 2.00% | **2.00%** | 2.00% |
| Rate of increase in health care cost trends[1] | **—** | — | **4.04%** | 4.04% |

1 5.19% per annum in 2019, grading down to 4.04% per annum in and after 2031 (2017 – 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2018 and 2017. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

| Year ended December 31 | **2018** | 2017 |
|---|---|---|
| **Pension Benefits:** | | |
| Weighted average expected rate of return on plan assets | **6.50%** | 6.50% |
| Weighted average discount rate | **3.40%** | 3.90% |
| Rate of compensation scale escalation (long-term) | **2.50%** | 2.50% |
| Rate of cost of living increase | **2.00%** | 2.00% |
| Average remaining service life of employees (years) | **15** | 15 |
| **Post-Retirement and Post-Employment Benefits:** | | |
| Weighted average discount rate | **3.40%** | 3.90% |
| Rate of compensation scale escalation (long-term) | **2.50%** | 2.50% |
| Rate of cost of living increase | **2.00%** | 2.00% |
| Average remaining service life of employees (years) | **15.5** | 15.2 |
| Rate of increase in health care cost trends[1] | **4.04%** | 4.36% |

1 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2017 – 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the PBO for the post-retirement and post-employment benefits at December 31, 2018 and 2017 is as follows:

| December 31 (millions of dollars) | **2018** | 2017 |
|---|---|---|
| **Projected benefit obligation:** | | |
| Effect of a 1% increase in health care cost trends | **230** | 250 |
| Effect of a 1% decrease in health care cost trends | **(175)** | (189) |

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2018 and 2017 is as follows:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| **Service cost and interest cost:** | | |
| Effect of a 1% increase in health care cost trends | 23 | 29 |
| Effect of a 1% decrease in health care cost trends | (16) | (20) |

The following approximate life expectancies were used in the mortality assumptions to determine the PBO for the pension and post-retirement and post-employment plans at December 31, 2018 and 2017:

| December 31, 2018 Life expectancy at 65 for a member currently at | | | | December 31, 2017 Life expectancy at 65 for a member currently at | | | |
|---|---|---|---|---|---|---|---|
| Age 65 | | Age 45 | | Age 65 | | Age 45 | |
| Male | Female | Male | Female | Male | Female | Male | Female |
| 22 | 25 | 23 | 25 | 22 | 24 | 23 | 24 |

## Estimated Future Benefit Payments

At December 31, 2018, estimated future benefit payments to the participants of the Plans were:

| (millions of dollars) | Pension Benefits | Post-Retirement and Post-Employment Benefits |
|---|---|---|
| 2019 | 335 | 56 |
| 2020 | 343 | 58 |
| 2021 | 352 | 59 |
| 2022 | 360 | 60 |
| 2023 | 367 | 61 |
| 2024 through to 2028 | 1,915 | 326 |
| Total estimated future benefit payments through to 2028 | 3,672 | 620 |

## Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| **Pension Benefits:** | | |
| Actuarial loss (gain) for the year | (350) | 159 |
| Amortization of actuarial losses | (84) | (79) |
| | (434) | 80 |
| **Post-Retirement and Post-Employment Benefits:** | | |
| Actuarial loss (gain) for the year | (158) | (197) |
| Amortization of actuarial losses | (15) | (16) |
| Amortization of prior service cost | (3) | — |
| Amounts not subject to regulatory treatment | 10 | 6 |
| | (166) | (207) |

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2018 and 2017:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| **Pension Benefits:** | | |
| Actuarial loss | **547** | 981 |
| **Post-Retirement and Post-Employment Benefits:** | | |
| Actuarial loss (gain) | **(130)** | 36 |

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

| | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| December 31 (millions of dollars) | 2018 | 2017 | 2018 | 2017 |
| Actuarial loss (gain) | **55** | 84 | **(1)** | 2 |

## Pension Plan Assets

### Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

### Pension Plan Asset Mix

At December 31, 2018, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

| | Target Allocation (%) | Pension Plan Assets (%) |
|---|---|---|
| Equity securities | 45 | 50 |
| Debt securities | 35 | 41 |
| Other[1] | 20 | 9 |
| | 100 | 100 |

1 Other investments include real estate and infrastructure investments.

At December 31, 2018, the Pension Plan held $18 million (2017 – $11 million) Hydro One corporate bonds and $546 million (2017 – $415 million) of debt securities of the Province.

### Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2018 and 2017. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2018 and 2017, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions, and also by ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

**Fair Value Measurements**

The following tables present the Pension Plan assets and liabilities measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2018 and 2017:

| December 31, 2018 (millions of dollars) | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Pooled funds | — | 21 | 651 | 672 |
| Cash and cash equivalents | 210 | — | — | 210 |
| Short-term securities | — | 78 | — | 78 |
| Derivative instruments | — | (7) | — | (7) |
| Corporate shares – Canadian | 115 | — | — | 115 |
| Corporate shares – Foreign | 3,222 | 183 | — | 3,405 |
| Bonds and debentures – Canadian | — | 2,506 | — | 2,506 |
| Bonds and debentures – Foreign | — | 197 | — | 197 |
| Total fair value of plan assets[1] | 3,547 | 2,978 | 651 | 7,176 |

1 At December 31, 2018, the total fair value of Pension Plan assets and liabilities excludes $35 million of interest and dividends receivable, $10 million of pension administration expenses payable, $6 million of sold investments receivable, and $2 million of purchased investments payable.

| December 31, 2017 (millions of dollars) | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| Pooled funds | — | 16 | 549 | 565 |
| Cash and cash equivalents | 153 | — | — | 153 |
| Short-term securities | — | 109 | — | 109 |
| Derivative instruments | — | 5 | — | 5 |
| Corporate shares – Canadian | 921 | — | — | 921 |
| Corporate shares – Foreign | 3,307 | 125 | — | 3,432 |
| Bonds and debentures – Canadian | — | 1,879 | — | 1,879 |
| Bonds and debentures – Foreign | — | 194 | — | 194 |
| Total fair value of plan assets[1] | 4,381 | 2,328 | 549 | 7,258 |

1 At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable, and $1 million of purchased investments payable.

See Note 17 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

**Changes in the Fair Value of Financial Instruments Classified in Level 3**

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2018 and 2017. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below could, therefore, include changes in fair value based on both observable and unobservable inputs. The Level 3 financial instruments are comprised of pooled funds whose valuations are provided by the investment managers. Sensitivity analysis is not provided as the underlying assumptions used by the investment managers are not available.

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Fair value, beginning of year | 549 | 425 |
| Realized and unrealized gains (losses) | 59 | (31) |
| Purchases | 90 | 171 |
| Sales and disbursements | (47) | (16) |
| Fair value, end of year | 651 | 549 |

There were no significant transfers between any of the fair value levels during the years ended December 31, 2018 and 2017.

**Valuation Techniques Used to Determine Fair Value**

Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments.

Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The notional principal amount of contracts outstanding as at December 31, 2018 was $299 million (2017 – $279 million), the most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The net realized loss on contracts for the year ended December 31, 2018 was $7 million (2017 – $1 million net realized gain). The terms to maturity of the forward exchange contracts at December 31, 2018 are within three months. The fair value is determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Corporate shares which are valued based on quoted prices in active markets, but held within a pension investment holding company, are categorized as Level 2. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

## 20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2018 and 2017:

| Year ended December 31, 2018 (millions of dollars) | PCB | LAR | Total |
|---|---|---|---|
| Environmental liabilities – beginning | 134 | 62 | 196 |
| Interest accretion | 5 | 1 | 6 |
| Expenditures | (16) | (6) | (22) |
| Revaluation adjustment | (15) | — | (15) |
| Environmental liabilities – ending | 108 | 57 | 165 |
| Less: current portion | (15) | (11) | (26) |
| | 93 | 46 | 139 |

| Year ended December 31, 2017 (millions of dollars) | PCB | LAR | Total |
|---|---|---|---|
| Environmental liabilities – beginning | 143 | 61 | 204 |
| Interest accretion | 6 | 2 | 8 |
| Expenditures | (16) | (8) | (24) |
| Revaluation adjustment | 1 | 7 | 8 |
| Environmental liabilities – ending | 134 | 62 | 196 |
| Less: current portion | (20) | (8) | (28) |
| | 114 | 54 | 168 |

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

| December 31, 2018 (millions of dollars) | PCB | LAR | Total |
|---|---|---|---|
| Undiscounted environmental liabilities | 118 | 58 | 176 |
| Less: discounting environmental liabilities to present value | (10) | (1) | (11) |
| Discounted environmental liabilities | 108 | 57 | 165 |

| December 31, 2017 (millions of dollars) | PCB | LAR | Total |
|---|---|---|---|
| Undiscounted environmental liabilities | 142 | 64 | 206 |
| Less: discounting environmental liabilities to present value | (8) | (2) | (10) |
| Discounted environmental liabilities | 134 | 62 | 196 |

At December 31, 2018, the estimated future environmental expenditures were as follows:

| (millions of dollars) | |
|---|---|
| 2019 | 26 |
| 2020 | 29 |
| 2021 | 32 |
| 2022 | 31 |
| 2023 | 28 |
| Thereafter | 30 |
| | 176 |

Hydro One records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

### PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $118 million (2017 – $142 million). These expenditures are expected to be incurred over the period from 2019 to 2024. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2018 to decrease the PCB environmental liability by $15 million (2017 – increase by $1 million).

### LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $58 million (2017 – $64 million). These expenditures are expected to be incurred over the period from 2019 to 2044. As a result of its annual review of environmental liabilities, no revaluation adjustment to the LAR environmental liability was recorded in 2018 (2017 – revaluation adjustment was recorded to increase the LAR environmental liability by $7 million).

## 21. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 4.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2018 to increase the asset retirement liability by $1 million (2017 – $nil).

At December 31, 2018, Hydro One had recorded asset retirement obligations of $10 million (2017 – $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

## 22. SHARE CAPITAL

### Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2018, the Company had 595,938,975 (2017 – 595,386,711) common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

The following tables present the changes to common shares during the years ended December 31, 2018 and 2017:

| Year ended December 31, 2018 (number of shares) | Ownership by Public | Ownership by Province | Total |
|---|---|---|---|
| Common shares – beginning | 312,974,063 | 282,412,648 | 595,386,711 |
| Common shares issued – share grants[1] | 481,460 | — | 481,460 |
| Common shares issued – LTIP[2] | 70,804 | — | 70,804 |
| Common shares – ending | 313,526,327 | 282,412,648 | 595,938,975 |
| | 52.6% | 47.4% | 100% |

1 In 2018, Hydro One issued from treasury 481,460 common shares in accordance with provisions of the Power Workers' Union (PWU) and the Society Share Grant Plans.

2 In 2018, Hydro One issued from treasury 70,804 common shares in accordance with provisions of the LTIP.

| Year ended December 31, 2017 (number of shares) | Ownership by Public | Ownership by Province | Total |
|---|---|---|---|
| Common shares – beginning | 178,196,340 | 416,803,660 | 595,000,000 |
| Secondary offering[1] | 120,000,000 | (120,000,000) | — |
| Common shares issued – share grants[2] | 371,611 | — | 371,611 |
| Common shares issued – LTIP[3] | 15,100 | — | 15,100 |
| Sale of common shares[4] | 14,391,012 | (14,391,012) | — |
| Common shares – ending | 312,974,063 | 282,412,648 | 595,386,711 |
| | 52.6% | 47.4% | 100% |

1 In May 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

2 In 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the PWU Share Grant Plan.

3 In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.

4 In December 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

### Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2018 and 2017, two series of preferred shares were authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2018 and 2017, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2018, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

### Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

## 23. DIVIDENDS

In 2018, preferred share dividends in the amount of $18 million (2017 – $18 million) and common share dividends in the amount of $542 million (2017 – $518 million) were declared.

## 24. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income (loss) attributable to common shareholders of Hydro One by the weighted-average number of common shares outstanding.

Diluted EPS is calculated by dividing net income (loss) attributable to common shareholders of Hydro One by the weighted-average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the LTIP, which are calculated using the treasury stock method.

| Year ended December 31 | 2018 | 2017 |
|---|---|---|
| Net income (loss) attributable to common shareholders (millions of dollars) | **(89)** | 658 |
| Weighted average number of shares | | |
| Basic | **595,756,470** | 595,287,586 |
| Effect of dilutive stock-based compensation plans | **2,147,473** | 2,234,665 |
| Diluted | **597,903,943** | 597,522,251 |
| EPS | | |
| Basic | **$ (0.15)** | $ 1.11 |
| Diluted | **$ (0.15)** | $ 1.10 |

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS as conditions for closing the Merger were not met as at December 31, 2018. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), the Convertible Debentures were redeemed on February 8, 2019.

## 25. STOCK-BASED COMPENSATION

### Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of the Society (formerly the Society of Energy Professionals) (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in its Initial Public Offering (IPO). The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in its IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2018, 481,460 common shares were issued under the Share Grant Plans (2017 – 371,611). Total share based compensation recognized during 2018 was $12 million (2017 – $17 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2018 and 2017 is presented below:

| Year ended December 31, 2018 | Share Grants (number of common shares) | | Weighted-Average Price |
|---|---|---|---|
| Share grants outstanding – beginning | 4,825,732 | $ | 20.50 |
| Vested and issued[1] | (481,460) | | — |
| Forfeited | (110,117) | $ | 20.50 |
| Share grants outstanding – ending | 4,234,155 | $ | 20.50 |

1 In 2018, Hydro One issued from treasury 481,460 common shares to eligible employees in accordance with provisions of the PWU and the Society Share Grant Plans.

| Year ended December 31, 2017 | Share Grants (number of common shares) | | Weighted-Average Price |
|---|---|---|---|
| Share grants outstanding – beginning | 5,334,415 | $ | 20.50 |
| Vested and issued[1] | (371,611) | | — |
| Forfeited | (137,072) | $ | 20.50 |
| Share grants outstanding – ending | 4,825,732 | $ | 20.50 |

1 In 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.

### Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of DSU awards activity under the Director' DSU Plan during the years ended December 31, 2018 and 2017 is presented below:

| Year ended December 31 (number of DSUs) | 2018 | 2017 |
|---|---|---|
| DSUs outstanding – beginning | 187,090 | 99,083 |
| Granted | 82,375 | 88,007 |
| Settled | (222,768) | — |
| DSUs outstanding – ending | 46,697 | 187,090 |

For the year ended December 31, 2018, an expense of $1 million (2017 – $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2018, a liability of $1 million (2017 – $4 million) related to Directors' DSUs has been recorded at the December 31, 2018 closing price of the Company's common shares of $20.25. This liability is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

DSUs related to the Company's former Board of Directors were settled at the June 29, 2018 (last business day in June 2018) closing price of the Company's common shares of $20.04, with an amount of approximately $5 million paid during the fourth quarter of 2018.

## Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of DSU awards activity under the Management DSU Plan during the years ended December 31, 2018 and 2017 is presented below:

| Year ended December 31 (number of DSUs) | 2018 | 2017 |
|---|---|---|
| DSUs outstanding – beginning | **67,829** | — |
| Granted | **40,467** | 68,897 |
| Paid | **—** | (1,068) |
| DSUs outstanding – ending | **108,296** | 67,829 |

For the year ended December 31, 2018, an expense of $1 million (2017 – $2 million) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2018, a liability of $2 million (2017 – $2 million) consisted of the following:

- $1 million recorded at the June 29, 2018 (last business day in June 2018) closing price of the Company's common shares of $20.04 (2017 – $22.40) related to previously awarded Management DSUs to the Company's former President and Chief Executive Officer (CEO) included in accounts payable and other current liabilities (2017 – $1 million included in long-term accounts payable and other liabilities; and
- $1 million recorded at the December 31, 2018 closing price of the Company's common shares of $20.25 (2017 – $22.40) related to other Management DSUs included in long-term accounts payable and other liabilities (2017 – $1 million).

## Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2018, Company contributions made under the ESOP were $2 million (2017 – $2 million).

## LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

### PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2018 and 2017 is presented below:

| | PSUs | | RSUs | |
|---|---|---|---|---|
| Year ended December 31 (number of units) | 2018 | 2017 | 2018 | 2017 |
| Units outstanding – beginning | **429,980** | 230,600 | **393,430** | 254,150 |
| Granted | **445,120** | 303,240 | **345,790** | 242,860 |
| Vested and issued | **(123)** | (609) | **(106,591)** | (14,079) |
| Forfeited | **(31,767)** | (103,251) | **(31,849)** | (89,501) |
| Settled | **(238,030)** | — | **(158,310)** | — |
| Units outstanding – ending | **605,180** | 429,980 | **442,470** | 393,430 |

The grant date total fair value of the awards granted in 2018 was $16 million (2017 – $13 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2018 was $15 million (2017 – $6 million). The expense recognized in 2018 included $5 million related to previously awarded PSUs and RSUs to the Company's former President and CEO for which costs had not previously been recognized. These awards, consisting of 238,030 PSUs and 158,310 RSUs, were settled in 2018 through a one-time cash settlement arrangement.

**Stock Options**

The Company is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, the Company granted 1,450,880 stock options (2017 – nil). The stock options granted are exercisable for a period not to exceed seven years from the date of grant and vest evenly over a three-year period on each anniversary of the date of grant.

The fair value based method is used to measure compensation expense related to stock options and the expense is recognized over the vesting period on a straight-line basis. The fair value of the stock option awards granted was estimated on the date of grant using a Black-Scholes valuation model.

Stock options granted and the weighted-average assumptions used in the valuation model for options granted during 2018 are as follows:

| | |
|---|---|
| Exercise price[1] | $ 20.70 |
| Grant date fair value per option | $ 1.66 |
| Valuation assumptions: | |
| Expected dividend yield[2] | 3.78% |
| Expected volatility[3] | 15.01% |
| Risk-free interest rate[4] | 2.00% |
| Expected option term[5] | 4.5 years |

1 Hydro One common share price on the date of the grant.
2 Based on dividend and Hydro One common share price on the date of the grant.
3 Based on average daily volatility of peer entities for a 4.5-year term.
4 Based on bond yield for an equivalent Canadian government bond.
5 Determined using the option term and the vesting period.

A summary of stock options activity during 2018 and 2017 is presented below:

| Year ended December 31 (number of stock options) | 2018 | 2017 |
|---|---|---|
| Stock options outstanding – beginning | — | — |
| Granted[1] | 1,450,880 | — |
| Cancelled[2] | (500,970) | — |
| Stock options outstanding – ending[1] | 949,910 | — |

1 All stock options granted and outstanding at December 31, 2018 are non-vested.
2 During 2018, 500,970 stock options previously awarded to the Company's former President and CEO were cancelled. The unrecognized compensation expense related to the cancelled stock options was $1 million.

The compensation expense related to stock options recognized by the Company during 2018 was $1 million. At December 31, 2018, there was $1 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted-average period of approximately three years.

## 26. NONCONTROLLING INTEREST

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest during the years ended December 31, 2018 and 2017:

| Year ended December 31, 2018 (millions of dollars) | Temporary Equity | Equity | Total |
|---|---|---|---|
| Noncontrolling interest – beginning | 22 | 50 | 72 |
| Distributions to noncontrolling interest | (3) | (5) | (8) |
| Net income attributable to noncontrolling interest | 2 | 4 | 6 |
| Noncontrolling interest – ending | 21 | 49 | 70 |

| Year ended December 31, 2017 (millions of dollars) | Temporary Equity | Equity | Total |
|---|---|---|---|
| Noncontrolling interest – beginning | 22 | 50 | 72 |
| Distributions to noncontrolling interest | (2) | (4) | (6) |
| Net income attributable to noncontrolling interest | 2 | 4 | 6 |
| Noncontrolling interest – ending | 22 | 50 | 72 |

## 27. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2018. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province.

Year ended December 31 (millions of dollars)

| Related Party | Transaction | 2018 | 2017 |
|---|---|---|---|
| **Province** | Dividends paid | 275 | 301 |
| **IESO** | Power purchased | 1,636 | 1,583 |
| | Revenues for transmission services | 1,615 | 1,521 |
| | Amounts related to electricity rebates | 477 | 357 |
| | Distribution revenues related to rural rate protection | 239 | 247 |
| | Distribution revenues related to the supply of electricity to remote northern communities | 35 | 32 |
| | Funding received related to CDM programs | 62 | 59 |
| **OPG** | Power purchased | 10 | 9 |
| | Revenues related to provision of services and supply of electricity | 9 | 8 |
| | Costs related to the purchase of services | — | 1 |
| **OEFC** | Power purchased from power contracts administered by the OEFC | 2 | 2 |
| **OEB** | OEB fees | 8 | 8 |

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

## 28. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Accounts receivable | 11 | 195 |
| Due from related parties | (2) | (95) |
| Other assets | 2 | 8 |
| Accounts payable | 2 | 7 |
| Accrued liabilities | 17 | (89) |
| Due to related parties | (68) | 10 |
| Accrued interest | (3) | (6) |
| Long-term accounts payable and other liabilities | (7) | (2) |
| Post-retirement and post-employment benefit liability | 25 | 85 |
| | (23) | 113 |

### Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the Consolidated Statements of Cash Flows for the years ended December 31, 2018 and 2017. The reconciling items include net change in accruals and capitalized depreciation.

| Year ended December 31, 2018 (millions of dollars) | Property, Plant and Equipment | Intangible Assets | Total |
|---|---|---|---|
| Capital investments | (1,454) | (121) | (1,575) |
| Reconciling items | 36 | 1 | 37 |
| Cash outflow for capital expenditures | (1,418) | (120) | (1,538) |

| Year ended December 31, 2017 (millions of dollars) | Property, Plant and Equipment | Intangible Assets | Total |
|---|---|---|---|
| Capital investments | (1,493) | (74) | (1,567) |
| Reconciling items | 26 | (6) | 20 |
| Cash outflow for capital expenditures | (1,467) | (80) | (1,547) |

### Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2018, capital contributions from these reassessments totalled $7 million (2017 – $9 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

### Supplementary Information

| Year ended December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Net interest paid | 519 | 475 |
| Income taxes paid | 17 | 12 |

## 29. CONTINGENCIES

### Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal.

To date, four putative class action lawsuits were filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in *Fink* has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants.

### Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself.

The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2018, the Company paid approximately $2 million (2017 – $2 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

## 30. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter:

| December 31, 2018 (millions of dollars) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter |
|---|---|---|---|---|---|---|
| Outsourcing and other agreements | 161 | 104 | 29 | 2 | 3 | 11 |
| Long-term software/meter agreement | 17 | 16 | 2 | 1 | 2 | 1 |
| Operating lease commitments | 7 | 11 | 4 | 1 | 1 | 4 |

### Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services. The agreement expires on February 28, 2021 for information technology services, on October 31, 2021 for supply chain services, and on December 31, 2019 for the remaining back-office services.

On March 1, 2018, Hydro One insourced its customer service operations, which had been previously outsourced to Inergi and Vertex Customer Management (Canada) Limited since 2002.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024, with an option for the Company to renew the agreement for an additional term of three years.

### Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

### Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2018, the Company made lease payments totalling $12 million (2017 – $12 million).

### Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter:

| December 31, 2018 (millions of dollars) | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Thereafter |
|---|---|---|---|---|---|---|
| Operating Credit Facilities | — | — | 250 | 2,300 | — | — |
| Letters of credit[1] | 182 | — | — | — | — | — |
| Guarantees[2] | 325 | — | — | — | — | — |

1 Letters of credit consist of letters of credit totalling $163 million related to retirement compensation arrangements, a $13 million letter of credit provided to the IESO for prudential support, $5 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

2 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

**Prudential Support**

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

**Retirement Compensation Arrangements**

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. A bank letter of credit has also been issued to provide security for Hydro One's retirement compensation arrangement trust agreement.

## 31. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

| Year ended December 31, 2018 (millions of dollars) | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| Revenues | 1,686 | 4,422 | 42 | 6,150 |
| Purchased power | — | 2,899 | — | 2,899 |
| Operation, maintenance and administration | 409 | 602 | 94 | 1,105 |
| Depreciation and amortization | 435 | 395 | 7 | 837 |
| **Income (loss) before financing charges and income taxes** | 842 | 526 | (59) | 1,309 |
| **Capital investments** | 985 | 577 | 13 | 1,575 |

| Year ended December 31, 2017 (millions of dollars) | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| Revenues | 1,578 | 4,366 | 46 | 5,990 |
| Purchased power | — | 2,875 | — | 2,875 |
| Operation, maintenance and administration | 375 | 593 | 98 | 1,066 |
| Depreciation and amortization | 420 | 390 | 7 | 817 |
| **Income (loss) before financing charges and income taxes** | 783 | 508 | (59) | 1,232 |
| **Capital investments** | 968 | 588 | 11 | 1,567 |

### Total Assets by Segment:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Transmission | 13,973 | 13,608 |
| Distribution | 9,325 | 9,259 |
| Other | 2,359 | 2,834 |
| **Total assets** | 25,657 | 25,701 |

### Total Goodwill by Segment:

| December 31 (millions of dollars) | 2018 | 2017 |
|---|---|---|
| Transmission | 157 | 157 |
| Distribution | 168 | 168 |
| **Total goodwill** | 325 | 325 |

All revenues, assets and substantially all costs, as the case may be, are earned, held or incurred in Canada.

## 32. SUBSEQUENT EVENTS

### (A) Dividends

On February 20, 2019, preferred share dividends of $5 million and common share dividends of $137 million ($0.23 per common share) were declared.

### (B) LTIP

On January 29, 2019, Hydro One issued from treasury 1,905 common shares in accordance with provisions of the LTIP.

### (C) Lake Superior Link Project

On February 15, 2018, Hydro One filed an application with the OEB to construct a transmission line (East-West Tie Line) in northwestern Ontario (Lake Superior Link Project). During 2018, the Company capitalized costs totaling approximately $11 million associated with this project. On February 11, 2019, the OEB awarded the project to a competitor, as directed by the Province on January 30, 2019. As a result, in the first quarter of 2019, Hydro One recognized an impairment loss of approximately $11 million associated with previously capitalized costs related to this project.

### (D) OEB Regulatory Decisions

**Deferred Income Tax Regulatory Asset**

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its Original Decision with respect to the rate-setting treatment of the benefits of the deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime. The OEB's Original Decision concluded that these benefits should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. The OEB has concluded that the Original Decision was reasonable and should be upheld. The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under US GAAP and as such the Company is required to update the consolidated financial statements to reflect the subsequent event in connection with filing its annual report on Form 40-F with the US Securities and Exchange Commission, so that they reflect events to the date of approval of the Form 40-F. As a result, the financial impact of this OEB decision has been reflected in these amended consolidated financial statements, as more fully discussed in Note 12 – Regulatory Assets and Liabilities.

**Hydro One Networks' 2018-2022 Distribution Rates**

Also, on March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates, in which it directed the Company to apply the Original Decision to Hydro One Networks' distribution rates. This aspect of the decision has been reflected in the adjustments discussed in Note 12 – Regulatory Assets and Liabilities. The other impacts from the OEB decision for Hydro One Networks' 2018-2022 distribution rates will be reflected prospectively in 2019.

# Board of Directors and Senior Leadership Team

## Board of Directors

1

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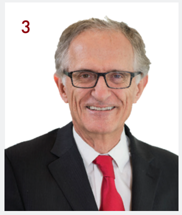
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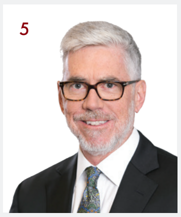
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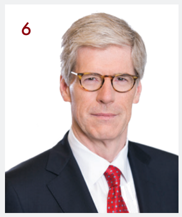
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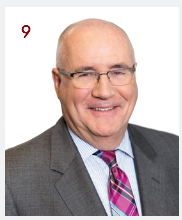
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1. **Tom Woods**, BASc, MBA, ICD.D
   Former Head of Canadian Corporate Banking, CFO, CRO, Vice Chair CIBC, Director Bank of America Corporation and Alberta Investment Management Corporation, Chair, Unity Health Toronto
2. **Cherie Brant**, JD
   Partner, Borden Ladner Gervais LLP, Director Anishnawbe Health Foundation, Member Canadian Council for Aboriginal Business, Research Advisory Board, Aboriginal Energy Working Group-IESO
3. **Blair Cowper-Smith**, LLM, ICD.D
   Principal and founder Erin Park Business Solutions, Former Chief Corporate Affairs Officer OMERS
4. **Anne Giardini**, O.C., O.B.C, Q.C, LLM
   Chancellor, Simon Fraser University, Former Canadian President Weyerhaeuser Company Limited, Former Director Nevsun Resources LTD
5. **David Hay**, LLB, ICD.D
   Managing Director Delgatie Incorporated, Former CEO New Brunswick Power Corporation, Former Vice-Chair and Managing Director of CIBC World Markets Inc., Director EPCOR, Council Member of the Council for Clean and Reliable Energy
6. **Timothy Hodgson**, MBA, FCPA, ICD.D
   Managing Partner Alignvest Management Corporation, Former Special Advisor to Bank of Canada Governor Mark Carney, Former CEO Goldman Sachs Canada, Director Public Sector Pension Investment Board (PSP Investments), Director MEG Energy, Director Alignvest Acquisition II Corporation
7. **Jessica McDonald**, ICD.D
   Chair, Canada Post Corporation, Former President & CEO BC Hydro & Power Authority, Director Coeur Mining Inc., Chair Trevali Mining Corporation, Member Council of Sustainable Development Technology Canada
8. **Russel Robertson**, FCPA, FCA, ICD.D
   Director, Former EVP and Head, Anti-Money Laundering, BMO Financial Group, Former Vice-Chair, Deloitte & Touche LLP, Director Bausch Health Companies Inc., Director Turquoise Hill Resources
9. **William Sheffield**, BSC, MBA, ICD.D
   Director, Former CEO Sappi Fine Papers, Director, Houston Wire & Cable Company, Director, Velan Inc., Former Board Member OPG
10. **Melissa Sonberg**, BSC, MHA, ICD.D
    Adjunct Professor, Executive-in-Residence, McGill University, Desautel Faculty of Management, Director Exchange Income Corporation, Former Senior Vice President, Human Resources & Corporate Affairs and Senior Vice President, Global Brands, Communications and External Affairs at AIMIA

## Senior Leadership Team

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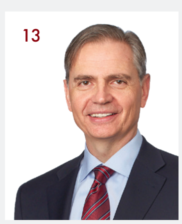
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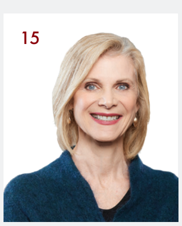
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11. **Paul Dobson**
    Acting President and CEO
12. **Jason Fitzsimmons**
    Chief Corporate Affairs and Customer Care Officer
13. **Greg Kiraly**
    Chief Operating Officer
14. **Chris Lopez**
    Acting Chief Financial Officer
15. **Judy McKellar**
    EVP, Chief Human Resources Officer
16. **Patrick Meneley**
    EVP, Chief Corporate Development Officer
17. **James (Jamie) Scarlett**
    EVP, Chief Legal Officer

For detailed biographical information of Hydro One Limited Board members and senior leadership, go to www.HydroOne.com/Investors.

The biographical information of Hydro One Limited Board members is based on information available to management as of March 8, 2019.

# Corporate and Shareholder Information

### Corporate Offices
483 Bay Street, South Tower
Toronto, ON
M5G 2P5
1.416.345.5000

www.HydroOne.com

### Customer Inquiries
*Customer Service:*
1.888.664.9376 or
CustomerCommunications@HydroOne.com

*Report an Emergency (24 hours):*
1.800.434.1235

### Shareholder Services
If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:

*Computershare Trust Company of Canada*
100 University Avenue, 8th Floor
Toronto, ON
M5J 2Y1
1.514.982.7555 or 1.800.564.6253
service@computershare.com

### Institutional Investors and Analysts
Institutional investors, securities analysts and others requiring additional financial information can visit www.HydroOne.com/Investors or contact us at:
1.416.345.6867
Investor.Relations@HydroOne.com or
Omar.Javed@HydroOne.com

### Media Inquiries
1.416.345.6868 or 1.877.506.7584
Media.Relations@HydroOne.com

### Sustainability
Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impacts on both. To learn more, visit www.HydroOne.com/OurCommitment or email CSR@HydroOne.com.

### Stock Exchange Listing
Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

### Independent Auditors
KPMG LLP

### Equity Index Inclusions
Dow Jones Select Utilities (Canada) Index
FTSE All-World Index Series
MSCI World (Canada) Index
S&P/TSX Composite Index
S&P/TSX Utilities Index
S&P/TSX Composite Dividend Index
S&P/TSX Composite Low Volatility Index
S&P/TSX Composite High Dividend Index

### Debt Securities
For details of the public debt securities of Hydro One and its subsidiaries, please refer to the "Debt Information" section under www.HydroOne.com/Investors.

### Online Information
Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of www.HydroOne.com/Investors where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, corporate social responsibility and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

### Common Share Dividend Information
*2019 Expected Dividend Dates**

| Record Date | Payment Date |
|---|---|
| March 13, 2019 | March 29, 2019 |
| June 12, 2019 | June 28, 2019 |
| September 12, 2019 | September 30, 2019 |
| December 11, 2019 | December 31, 2019 |

*Subject to Board approval

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

### Dividend Reinvestment Plan (DRIP)
Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit www.HydroOne.com/DRIP or Computershare Trust Company of Canada at www.InvestorCentre.com/HydroOne.

### Regulatory Stakeholders
Hydro One is committed to understanding the interests of maintaining and enhancing long-term relationships with its regulatory stakeholders.

Provincial Government, Ministry of Energy
Policy, legislation, regulations

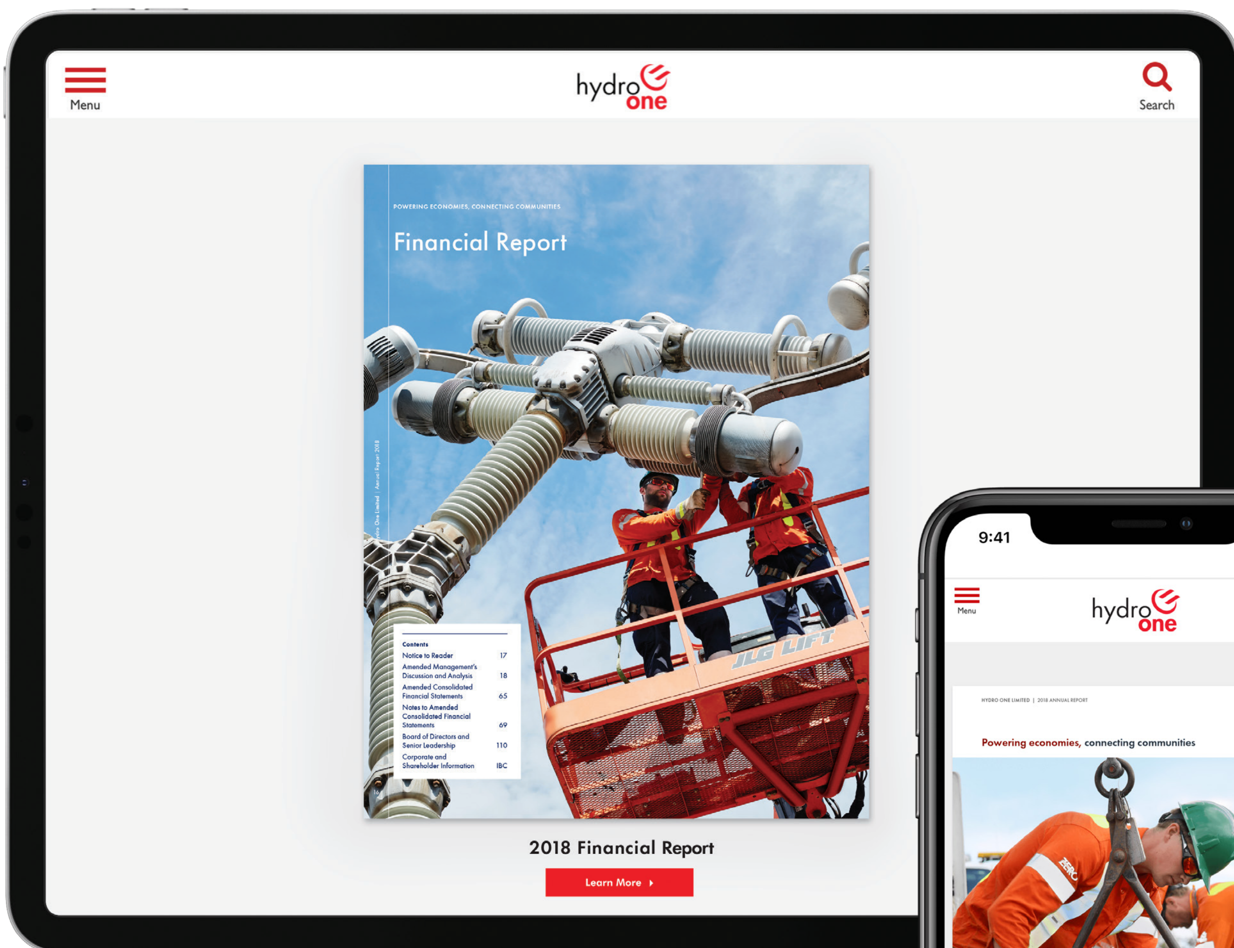
Ontario Energy Board (OEB)
Independent electric utility price and service quality regulation

Independent Electricity System Operator
Wholesale power market rules, intermediary, North American reliability standards

National Energy Board
Federal regulator, international power lines and substations

North American Electric Reliability Corporation
Continent-wide bulk power reliability standards, certification, monitoring

For more information, visit:
**www.HydroOne.com/Regulatory**





## Why Invest in Hydro One?

- Utility business in a stable and rate-regulated environment
- Pure-play electric company with no commodity price exposure
- Solid investment grade balance sheet
- Fully independent Board
- Stable and growing dividend

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LINKEDIN /COMPANY/HYDRO-ONE

# ISSUES LIST

## A. GENERAL

1. Are all elements of the proposed revenue requirement and their associated total bill impacts reasonable?

## B. REVENUE CAP APPLICATION

2. Is the proposed Incentive Rate Methodology consistent with the OEB's Rate Handbook?
3. Are the proposed industry-specific inflation factor and the proposed productivity factor appropriate?
4. Are the proposed annual updates appropriate?
5. Is the proposed Earnings Sharing Mechanism appropriate?

## C. TRANSMISSION SYSTEM PLAN

6. Has the investment planning process been appropriately considered? Does it adequately address the condition of the transmission system assets?

## D. PERFORMANCE

7. Is the proposed monitoring and reporting of performance adequate?

## E. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

8. Are the proposed spending levels for OM&A in 2020 appropriate, including consideration of factors such as system reliability and asset condition?
9. Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?
10. Is the proposed depreciation expense appropriate?

**F. RATE BASE & COST OF CAPITAL**

11. Are the amounts proposed for rate base and capital structure reasonable?
12. Is the forecast of long-term debt appropriate?
13. Is the 2021 update of the cost of long-term debt appropriate?

**G. DEFERRAL/VARIANCE ACCOUNTS**

14. Are the proposed deferral and variance accounts appropriate?

**H. COST ALLOCATION**

15. Is the proposed cost allocation appropriate?

# LIST OF WITNESSES

To be filed behind this tab if the OEB determines that an oral hearing is required.

# CURRICULA VITAE

Curricula Vitae information will be filed prior to the oral hearing as required.

# TRANSMISSION SYSTEM OVERVIEW

## 1. INTRODUCTION

NRLP is licensed by the Ontario Energy Board ("OEB") to own, operate and maintain transmission facilities in the Province of Ontario. This Exhibit provides an overview of a transmission system, a description of NRLP's transmission assets, and concludes with a discussion on the requirements for NRLP within the electricity industry and regulatory framework in Ontario.

## 2. TRANSMISSION SYSTEM BACKGROUND

The purpose of a transmission system is to transmit electricity between supply points and delivery points. Supply Points include generators, interconnections with other jurisdictions, and load customers with sufficient embedded generation to result in injections into the transmission system. Delivery points include load customers, including Local Distribution Companies ("LDCs"), end-use Transmission Customers and interconnections with other jurisdictions.

A simplified figure of a transmission system is provided in Figure 1. As depicted, a typical transmission system is a large interconnected electrical network that includes three key components: step-up facilities from supply points, high-voltage transmission lines, and step-down facilities to delivery points.

Ontario has several active, licenced transmitters. They include NRLP, B2M LP, Hydro One Networks Inc. (the largest transmitter of electricity in the province), Hydro One Sault Ste. Marie (formerly Great Lakes Power), Canadian Niagara Power Inc., and Five Nations Energy Inc.

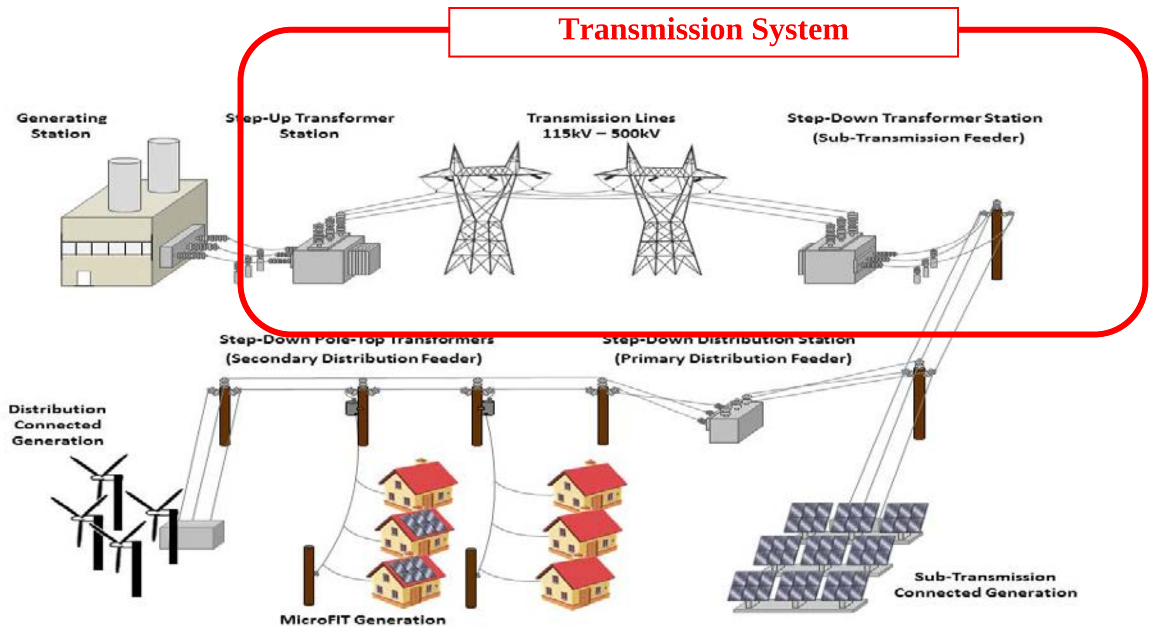


**Figure 1 – Simplified Electricity System**

## 3. DESCRIPTION OF NRLP TRANSMISSION ASSETS

NRLP's transmission assets are comprised solely of one 230kV double circuit transmission line housing the circuits known as Q26M and Circuit Q35M. These circuits have a combined capacity of approximately 1,200 MW.

The route of NRLP's 230kV double circuit transmission line runs along an existing Hydro One right-of-way between Allanburg West Junction and Middleport TS, as depicted in the map in Figure 2.

NRLP's assets include a new 230kV double circuit line from Allanburg West Junction, approximately 1 km away from Allanburg TS, to Middleport TS. Each circuit is approximately 76 km in length. HONI owns the terminating stations and line junctions (Allanburg TS, Middleport TS, and Allanburg West Junction).

The demarcation points for each of NRLP's circuits from HONI's transmission system are:

- Circuit Q26M: terminating at the west end of Allanburg West Junction at tower #6, inclusive, and at the south end at Middleport TS at tower #320, inclusive; and
- Circuit Q35M: terminating at the west end of Allanburg West Junction at tower #6, inclusive, and at the south end at Middleport TS at tower #320, inclusive.

Additionally, Hydro One owns from the line disconnects at Caledonia Q35M-C9 Junction and St. Anns Junction, which are normally open alternate supply points from Q35M to C9 and Q2AH respectively.

The major components of these circuits include overhead conductors, steel support structures and foundations, insulators, and connecting hardware. NRLP also has rights to HONI's existing transmission corridor on which the circuits are located. A summary of NRLP's key assets are provided in Table 1

**Table 1 – Asset Summary**

| **NRLP Assets** | |
|---|---|
| Fixed Assets (Net Book Value) | ~$120 Million |
| Transmission System Voltages | 230kV |
| Overhead Transmission Lines | 152 circuit km |
| Steel Support Structures | 325 towers |
| Line Insulators | 2300 strings |

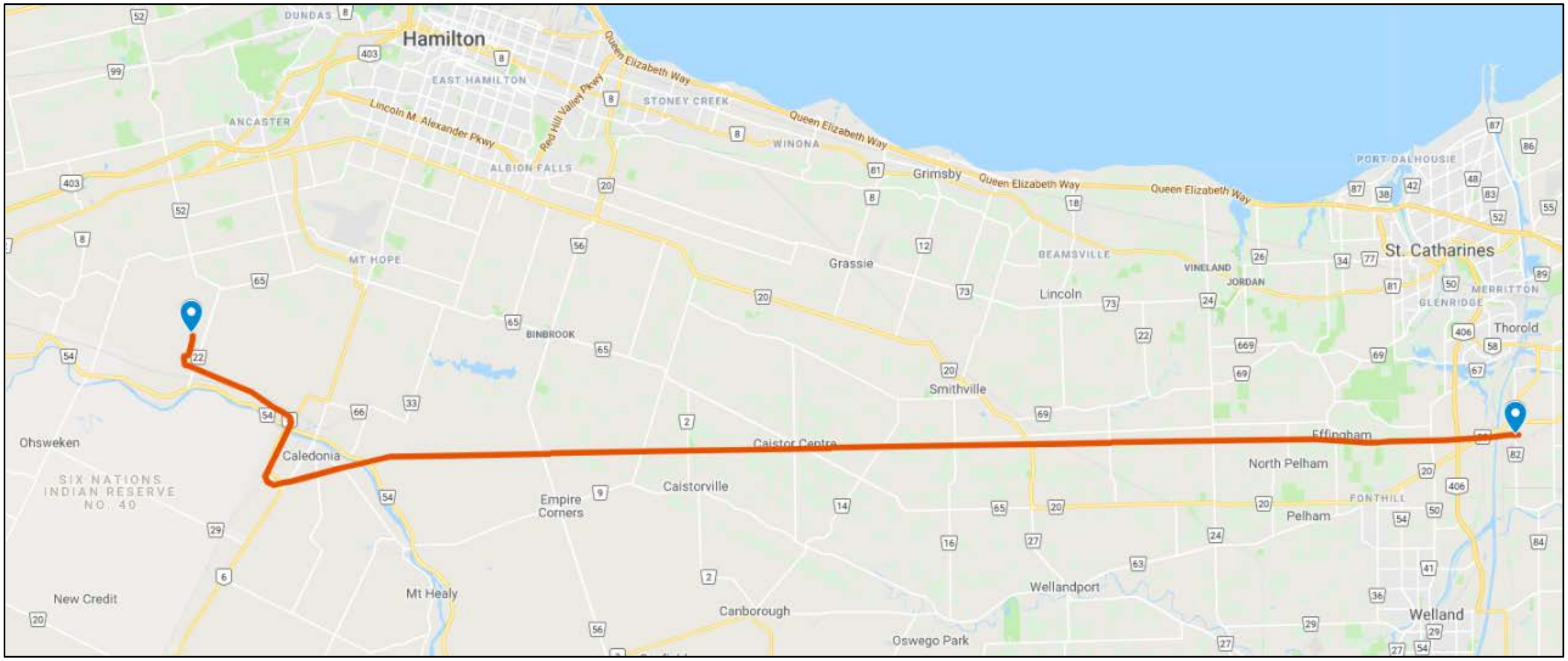


**Figure 2 – NRLP Transmission System Map**

## 4. ELECTRICITY INDUSTRY AND REGULATORY FRAMEWORK

NRLP is subject to direction from its owners, OEB decisions, and government legislation and regulations. Each of these sources has the potential to be a driver for change affecting NRLP policies, processes and work programs. When new legislation or regulations are passed, or when OEB decisions are released, NRLP responds by developing appropriate programs or initiatives to implement the required changes in a cost-effective fashion.

The following provides a summary of the key electricity legislation and regulation, industry standards and guidelines and other relevant legislation that governs and drives NRLP's transmission business.

### 4.1 INDUSTRY AND REGULATORY ENVIRONMENT IN ONTARIO

Within the Ontario electricity industry, the Ministry of Energy, Northern Development and Mines sets legislative and regulatory requirements through changes to the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998*.

The OEB sets transmission rates, issues codes and licences, and grants approval for construction of new transmission lines greater than two kilometres. The Transmission System Code ("TSC"), issued by the OEB, sets out the obligations of electricity transmitters regarding their customers. The TSC also addresses standards for the operation, maintenance, management and expansion of transmission systems. NRLP is bound by the terms of its transmission licence to adhere to the requirements of the TSC and is required to operate and maintain its system in accordance with "good utility practice". The TSC and the Independent Electricity Operator's (IESO's) Market Rules also require all customers directly connected to the transmission system to enter into a connection agreement with their transmitter. NRLP does not have any customers that are directly connected to its assets and does not foresee being in a position to acquire customers in the foreseeable future.

The IESO administers the electricity market and directs the operation of the power system in Ontario while ensuring that its extensive planning, conservation, market and procurement capabilities serve the province's long-term needs. The IESO-controlled grid provides the infrastructure for transmitting large volumes of electrical energy from major generation sources to major load centres. The NRLP transmission assets provide transmission capacity, which the IESO makes available to market participants.

### 4.2 NORTH AMERICAN RELIABILITY FRAMEWORK

The North American Electric Reliability Corporation ("NERC") was established in the United States in 1968, in response to the 1965 blackout, to ensure the reliability of the North American bulk power system. NERC develops and enforces reliability standards, monitors the bulk power system through system awareness, and assesses seasonal and long-term power system reliability annually.

Following the 2003 Northeast blackout, the *U.S. Energy Policy Act* of 2005 authorized the creation of a self-regulatory Electricity Reliability Organization ("ERO") that would span North America. The legislation stated that compliance with reliability standards would be mandatory and enforceable. In July 2006, NERC was certified as the ERO for in the United States. While NERC has retained overall accountability for compliance enforcement, NERC has delegated certain functions respecting compliance enforcement with reliability standards to Northeast Power Coordinating Council (NPCC).

In November 2006, IESO entered into a Memorandum of Understanding with NERC and NPCC. According to this MOU, the IESO will be the sole entity in Ontario accountable to NPCC and NERC and will be subject to compliance monitoring and enforcement processes pertinent to NERC Reliability Standards and NPCC Reliability Criteria. The IESO, through its Market Assessment and Compliance Division (MACD), enforces the NERC reliability standards and NPCC criteria through the Ontario Market Rules.

As a licensed transmitter, NRLP has a regulatory obligation to comply with the planning, operating, and reliability criteria and standards adopted by NERC and NPCC as stated in the IESO Market Rules. The IESO is responsible for monitoring and enforcing the reliability standards in Ontario, where market participants are subject to monetary sanctions for confirmed violations.

## 4.3 OTHER RELEVANT LEGISLATION

### 4.3.1 ENVIRONMENTAL LEGISLATION

Transmitters such as NRLP are subject to a wide range of federal and provincial legislation, regulation and standards related to environmental impacts. Many others can apply in specific circumstances, but the following are the major statutes that govern transmission activities:

1. *Environmental* Assessment *Act*
2. *Environmental Protection Act*
3. *Fisheries Act / Fish and Wildlife Conservation Act, 1997*
4. *Species at Risk Act / Endangered Species Act, 2007*
5. *Dangerous Goods Transportation Act*
6. *Pesticides Act*
7. *Ontario Water Resources Act*
8. *Conservation Authorities Act*
9. *Ontario Heritage Act*
10. *Forest Fires Prevention Act*
11. *Public Lands Act*

*12. Public Transportation and Highway Improvement Act*

### 4.3.2 SAFETY STANDARDS

Safety is of utmost importance in NRLP's transmission work activities. NRLP is committed to complying with safety standards and regulations following those established by HONI and the Electrical Safety Authority ("ESA").

The *Occupational Health and Safety Act* requires NRLP to comply with industrial design and construction safety regulations, and NRLP must also comply with the health regulations of the Ministry of Health under the *Health Protection and Promotion Act.*

### 4.3.3 INDUSTRY STANDARDS

NRLP also complies with other relevant national and international standards such as the Canadian Standards Association ("CSA"), the Institute of Electrical and Electronic Engineers ("IEEE") and the International Electrotechnical Commission ("IEC") for the design of its transmission system and equipment.

## 4.4 COMPLIANCE MATTERS

Pursuant to the Filing Requirements, NRLP states that there are no outstanding areas of non-compliance which have had an effect on this Application, and NRLP is therefore not seeking any relief to resolve any non-compliances issues.

# STRATEGIC PLAN

## 1. INTRODUCTION

This Exhibit provides an overview of NRLP's business activities and values utilized in the development of an overall strategy for the company. It also will outline NRLP's strategic goals and vision that drives the partnership's five-year plan as presented in this Application.

## 2. DESCRIPTION OF NRLP BUSINESS ACTIVITIES

NRLP is licensed by the Ontario Energy Board ("OEB") to own, operate and maintain transmission facilities in the Province of Ontario. NRLP's business activities consist of the management of its transmission assets to meet reliability standards and satisfy regulatory, environmental, and legal requirements. HOIP, the general partner of NRLP, is responsible for ensuring that the transmission assets owned by NRLP are operated and maintained in accordance with these requirements. HOIP will carry out these functions through a management and operations services agreement with HONI, a copy of which is included as Attachment 1 to Exhibit F, Tab 3, Schedule 1.

## 3. NRLP'S VALUES

NRLP, as part of the Hydro One family of companies, is driven primarily by the values of health and safety, and stewardship. The work performed on NRLP's assets is conducted in an environment that can be dangerous for both workers and the public. Therefore, safety is of the utmost importance. The partnership seeks to demonstrate sound stewardship in a manner that respects customers' needs and the environment. NRLP's strategy and business values must operate with rates that can balance the financing of investment in infrastructure while maintaining affordable and reliable service.

NRLP is set to be 45% owned by First Nations over whose traditional territory the transmission line crosses. Respect for Indigenous peoples and their traditions is another key value of the partnership.

## 4. STRATEGIC OBJECTIVES

NRLP's strategic objectives consist of the following:

- Oversee a service level agreement with HONI that supports creating an injury-free workplace and maintaining public safety;
- Foster positive relationships with the owners of the partnership and their communities;
- Maintain a reliable, cost-effective transmission system;
- Protect and sustain the environment for future generations; and,
- Maintain a commercial culture that increases value for its owners.

The five-year vision associated with NRLP's strategic objectives is shown in Table 1. In managing its transmission assets, NRLP is committed to meeting the OEB's Renewed Regulatory Framework ("RRF") outcomes as demonstrated by the alignment of NRLP's strategic objectives to the RRF outcomes.

**Table 1 - NRLP Strategic Objectives**

| RRF Outcomes | Strategic Objectives | Five-Year Vision |
|---|---|---|
| Customer Focus | Foster Indigenous Relationships | Continue to maintain effective and beneficial relationships. |
| Operational Effectiveness | Injury-Free | Ensure NRLP's operations and management services agreement is executed in accordance with good utility practice for employee and public safety. |
| | Reliable Transmission | Continue to maintain a reliable transmission system. |
| | Cost Control | Strive to minimize costs and pass on savings to the customers of the province. |
| Public Policy Responsiveness | Protecting the Environment | Sustainably manage NRLP's environmental footprint. |
| Financial Performance | Owner's Value | Achieve the Regulated Return On Equity allowed by the Ontario Energy Board. |

In the implementation of these strategic objectives, NRLP works directly with HONI to review maintenance programs and work plans for efficiency, reliability and safety. The financial performance of NRLP is closely monitored and the timing of expenditures adjusted as required to maintain partner returns at expected levels. Furthermore, NRLP is proposing to track its performance by utilizing a set of outcome measures as documented in Exhibit D, Tab 1, Schedule 1 to ensure that NRLP satisfies its five-year plan.

Like other transmitters, NRLP may face challenges in implementing its plan to achieve the objectives listed above. External factors including unforeseen weather events and material changes to codes and standards, can cause necessary changes in the implementation of the plan that may not have been expected. Resourcing can also affect the timing of work execution. However, the work itself must be completed to ensure compliance with regulatory requirements and good utility practice, and to ensure that expenses will not lead to deficient returns. The communities that the Indigenous partners serve are modest entities that are financially unable to sustain substantial losses of return without affecting the delivery of important services to their community members. Therefore, consistent returns for NRLP are crucial.

# SUMMARY OF CAPITAL EXPENDITURES AND IN-SERVICE ADDITIONS

The 230kV double circuit transmission line was energized on August 30, 2019. At this point in the transmission line's life cycle, capital spending of a planned nature on the assets is not required. Therefore, NRLP has no capital spending planned (or associated in-service additions) over the five-year horizon of this Application. Further details on the life cycle and condition assessments are included in NRLP's Transmission System Plan found as Attachment 1 to this Exhibit.

A 230kV dual circuit transmission line, if maintained properly, is extremely durable and resilient in normal circumstances. However, extraordinary events (including tornados and ice formations) can occur and cause damage to the line. These types of devastating weather events, while uncommon, may result in unplanned capital spending to repair the system.

To address the risk of major storm damage or other events, NRLP is proposing to utilize the OEB's *z-factor* approach analogous to that provided to B2M LP[1] to seek relief for unplanned spending if necessary in the future. NRLP is satisfied with the efficacy of this mechanism to protect the partners from the impacts that could result from unforeseen events and is not requesting any additional mechanism to be created.

[1] See EB-2015-0026, Decision and Order, page 10

# Transmission System Plan

Test Year and Forecast Period: 2020-2024

# Niagara Reinforcement Limited Partnership

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# 1.0 INTRODUCTION

Niagara Reinforcement Limited Partnership ("NRLP") prepared this 2020 to 2024 Transmission System Plan ("TSP") in accordance with Chapter 2 of the Ontario Energy Board's ("OEB") *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016, with further guidance from Chapter 3 and 5 of the OEB's Filing Requirements (*Incentive Regulation* and *Consolidated Distribution System Plan Filing Requirements*), revised on July 12, 2018 (together, the "Filing Requirements").

NRLP submits that this TSP is distinct from most Transmission and Distribution System Plans submitted to the OEB in that it is not being filed to support any capital funding. Accordingly, the planning tools, processes, and investments outlined in this TSP represent the current state of the assets owned by the partnership, and this TSP is submitted to support the information purposes of ratepayers and stakeholders.

# 2.0 TRANSMISSION SYSTEM PLAN

## 2.1 TRANSMISSION SYSTEM PLAN OVERVIEW (*OEB Filing Req. 5.2.1*)

This section summarizes the key components that make up the integrated TSP and contextualizes the quantitative and qualitative information provided throughout.

### 2.1.1 KEY ELEMENTS OF THE PLAN:

NRLP transmission assets are limited to the components of a single 230kV double circuit transmission line. This line was placed into service on August 30, 2019. Given the new vintage of this line, no planned capital spending is required to meet the Applicant's business objectives over the 2020 to 2024 planning period. The absence of capital spending is expected to result in no in-service additions to grow the rate base of the Applicant during the planning period.

The forecast on-going OM&A expenses comprise a relatively small proportion of NRLP's request as expenditures in 2020 represent less than 10% of the total base revenue requirement. The proposed OM&A will ensure that the NRLP assets are operated and maintained in accordance with good utility practice and reliability standards.

### 2.1.2 CUSTOMERS' PREFERENCES AND EXPECTATIONS:

NRLP's 230kV double circuit transmission line is part of Ontario's bulk electric system, which helps to ensure the adequacy of supply to the province by connecting to major generating sources and delivering that power to major load centres in Ontario. NRLP has no delivery points and therefore has no customers that it directly serves. Thus, the partnership has not performed any independent customer research.

Research undertaken by other transmitters (e.g. Hydro One Networks Inc.) shows that most customers in Ontario want low rates and good reliability. NRLP's five-year plan supports these general customer objectives by proposing no planned capital spending and a minimal OM&A budget required to maintain NRLP's transmission reliability to keep ratepayer costs as low as possible. NRLP has signed an Agreement with Hydro One Networks Inc. ("HONI") to provide maintenance and operational services on the transmission line for the next five years. Having this service provider, with its breadth of capabilities and local knowledge, provides assurance that the assets will be operated and maintained in accordance with good utility practices and reliability standards.

### 2.1.3 ANTICIPATED SOURCES OF EFFICIENCIES:

The majority of NRLP's OM&A services are provided by HONI through a Service Level Agreement. The Agreement and the charges therefrom are in accordance with the Affiliate Relationships Code and are billed on a cost basis. Efficiencies gained by HONI are passed through to NRLP. NRLP's asset is a 230kV double circuit transmission line that is located close to several circuits and numerous other assets owned by HONI in the Niagara Region. Given the proximity of the assets, there are meaningful efficiencies inherent in having one party, HONI, plan and perform the work on all assets located in the same region.

NRLP's controllable costs are minimal but do include certain administrative expenses. These include such items as insurance and the Managing Director's office, which are being passed through to ratepayers.

NRLP is a brand new company owning new circuits that were just recently placed in service. However, NRLP is managed by the same General Partner and the same management staff as B2M LP, which has been operated successfully since December 2014. The staff involved have considerable experience in the Electricity Transmission industry. The General Partner is able to manage NRLP successfully by leveraging that expertise along with the availability of significant resources afforded by the agreements with HONI.

### 2.1.4 PERIOD COVERED AND VINTAGE OF INFORMATION:

This TSP covers the five-year forecast period from 2020 to 2024 inclusive. Any historical supporting information contained in this TSP is generally considered current as of year-end of 2018 unless otherwise noted.

### 2.1.5 IMPORTANT CHANGES TO THE ASSET MANAGEMENT PROCESS:

NRLP has retained HONI under a Service Level Agreement to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support. NRLP relies upon HONI's asset management process to develop its plan, as articulated in Section 3.0.

### 2.1.6 CONTINGENCIES OF PLAN:

NRLP is not proposing any capital expenditures over the five-year term of this Application. Therefore, there are no plan contingencies required.

### 2.1.7 GRID MODERNIZATION:

At this time, NRLP is not implementing any capital plans for future initiatives such as distributed energy resources, grid modernization or climate change.

## 2.2 COORDINATED PLANNING WITH THIRD PARTIES (*OEB Filing Req. 5.2.2*)

NRLP is not a lead transmitter for any of the regional planning regions. NRLP owns only one 230kV double circuit transmission line, which is part of the bulk system. The bulk system planning is under the purview of the Independent Electricity System Operator ("IESO") and is coordinated as part of that undertaking. If requested, NRLP will participate in the bulk system planning process and/or regional bulk system planning process, as per Section 3C of the Transmission System Code and the OEB endorsed Planning Process Working Group (the "PPWG") Report, in compliance with NRLP's obligations as a licensed transmitter. NRLP is not expecting such a request in the foreseeable future.

### 2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT (*OEB Filing Req. 5.2.3*)

NRLP is proposing to track its performance by utilizing the measures approved for B2M LP by the OEB in proceeding EB-2015-0026. This is to ensure that NRLP is meeting its five-year plan as described in this Application. The performance measures will be tracked annually, and the results of this tracking will be reported to the OEB at the next proceeding.

### 2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (*OEB Filing Req. 5.2.3*)

NRLP is a licensed transmitter of a 230kV double circuit transmission line but does not own any operable station assets and does not directly serve any customers. Therefore, the Applicant has neither deployed nor operationalized any smart meters or related technologies.

# 3.0 ASSET MANAGEMENT PROCESS

## 3.1 ASSET MANAGEMENT PROCESS OVERVIEW (*OEB Filing Req. 5.3.1*)

NRLP seeks to identify and prioritize asset maintenance and capital investments in an optimal way throughout the life cycle of its assets. To achieve this goal, NRLP intends to work with HONI in the future to undertake a strategic and methodical asset management process, drawing upon HONI's extensive expertise and experience to monitor its transmission system assets, identify and define needs, and determine the optimal timing for investment and maintenance activities in the future. In doing so, NRLP strives to ensure that it can deliver, over the long term, a level of transmission service that is responsive to operational needs, while also minimizing rate impacts and risks to electricity customers of Ontario.

## 3.2 OVERVIEW OF ASSETS MANAGED (*OEB Filing Req. 5.3.2*)

This section summarizes the detailed characteristics and data on the assets covered by the asset management process, including service area, system configuration, asset condition, and asset utilization.

### 3.2.1 FEATURES OF THE SERVICE AREA *(OEB FILING REQ. 5.3.2A)*

NRLP's 230kV double circuit transmission line includes the circuits specifically named Q26M and Q35M – running westerly from Allanburg West Junction located on Barron Road in the City of Thorold, traversing the counties of Welland, Lincoln and Haldimand, before terminating outside of Middleport TS located on Baptist Church Road in the County of Brant. A map of the territory covered by the line is displayed in Figure 1. These are primarily rural areas that generally allow for easy access to perform maintenance activities. However, the climate in these areas varies by season and may experience a variety of extreme weather conditions, such as blizzards, hail, ice storms, lightning, thunderstorms, extreme heat and tornadoes.

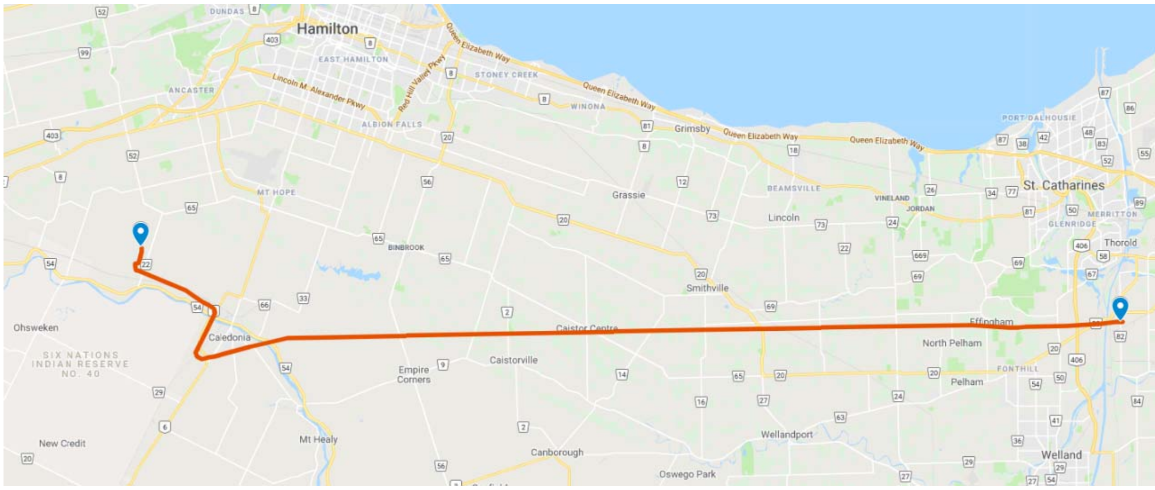


**Figure 1 – Map of Area Traversed by NRLP Line**

### 3.2.2 SYSTEM CONFIGURATION (*OEB FILING REQ. 5.3.2B*)

Table 1 provides a high-level description and quantity of major transmission assets that comprise the NRLP transmission line.

**Table 1 – Asset Summary**

| Asset Type | Description | Quantity |
|---|---|---|
| **Conductor** | The conductor of an overhead transmission line is the asset responsible for transporting electricity between system nodes. | 152 circuit km (456 km of conductor)[1] |
| **Steel Towers** | Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components. | 325 structures |
| **Insulators** | Insulators provide mechanical support for overhead conductors and must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached. | 2,300 strings |

These asset types are similar in all manner to those on HONI's transmission system. For further detailed descriptions of each asset component and the maintenance plans please

[1] Each of the 2 circuits is 76km in length with 3 phases (conductor strings) per circuit.

refer to HONI’s Transmission Rate Application (EB-2019-0028) in Exhibit B, Tab 1, Section 1, TSP Section 2.2.2.

### 3.2.3 ASSET CONDITION (OEB FILING REQ. 5.3.2C)

This section presents the service profile and condition of NRLP’s key transmission assets.

**In-Service Profile**

The Estimated Service Life (“ESL”) is defined as the average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and HONI’s historical asset retirement data. Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition. The asset was placed into service on August 30, 2019 and any reasonable expectation of failure due to ESL-related factors are several years or decades in the future.

**Condition**

The asset condition is noted in Table 2 - . Asset condition assessments are conducted for each asset as they reach an individual age threshold, which varies depending on asset type. Condition assessment results are categorized as:

- **Low Risk**: Assets have condition test results that indicate “like new” or have not yet reached an age where condition assessment is required.
- **Fair Risk**: Assets have condition test results that indicate minor deterioration but have not yet reached End of Life (“EOL”). These assets will be scheduled for reassessment at a later date, depending on the level of deterioration indicated by the test results.

- **High Risk**: Assets have condition test results that indicate EOL and in need of replacement within the plan period.

The term EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL, they may not be at EOL. At the same time, as the primary driver of replacement decisions, asset condition will be verified prior to work being undertaken.

**Table 2 - Asset Condition Summary**

| Asset Type | Quantity | High Risk | Fair Risk | Low Risk |
|---|---|---|---|---|
| **Conductors** | 152 km | 0% | 0% | 100% |
| **Steel Towers** | 325 towers | 0% | 0% | 100% |
| **Insulators** | 3,200 strings | 0% | 0% | 100% |

### 3.2.4 ASSET UTILIZATION (OEB FILING REQ. 5.3.2D)

NRLP's circuits have a combined capacity of approximately 1,200 MW. This 230kV double circuit transmission line is part of the bulk system and is operated in accordance with the planning criteria as part of the IESO-controlled grid. The adequacy of the bulk system is assessed by the IESO as part of the bulk system planning processes in accordance with NERC and NPCC Standards, including the IESO's Ontario Resource Transmission Assessment Criteria ("ORTAC"). The bulk system is currently within acceptable capacity levels.

## 3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES (*OEB Filing Req. 5.3.3*)

As documented in Section 3.1, NRLP will work with HONI to undertake a strategic and methodical asset management process, drawing upon HONI's extensive expertise and experience to monitor its transmission system assets. HONI has developed and implemented asset strategies for various components of the transmission system. The specific strategies related to overhead transmission line assets are outlined in detail in HONI's Transmission Rate Application (EB-2019-0082) in Exhibit B, Tab 1, Schedule 1, TSP Section 2.3.2. The following sections provide an overview of the specific operations and maintenance activities and replacement strategies applicable to NRLP.

### 3.3.1 ROUTINE OPERATION AND MAINTENANCE

On behalf of NRLP, HONI will perform routine operation and maintenance of NRLP's transmission assets as follows.

**Operating Services:**

Operating services include the monitoring and control of the transmission system, in accordance with the requirements of NRLP's Transmission Licence and all services required to fulfill all of NRLP's obligations under its Connection Agreement and the IESO-NRLP operating requirements. These services include, but are not limited to, the following:

- Alarm/asset monitoring, and minor control;
- Asset operation and switching;
- Emergency response to transmission system events;
- Outage processing;
- Crew dispatching;
- Record maintenance; and
- IT Support of the power system applications used by operators.

**Maintenance Services:**

The maintenance services include all planned and corrective maintenance services of the transmission line assets and rights-of-way in accordance with the requirements and obligations of NRLP's Transmission Licence. Further details are outlined below.

*a) Overhead Transmission Lines*

On behalf of NRLP, HONI will routinely inspect the overhead transmission lines by ground and aerial-based patrols to identify safety and reliability defects. HONI will also undertake emergency repairs and responses to restore power or minor corrective work to resolve reliability and safety problems with transmission line assets when necessary. As assets age, separate detailed assessments are also performed on individual conductor and structure assets to monitor the assets condition and determine when replacement is required.

*b) Transmission Rights-of-Way*

The strip of land that is occupied by a transmission line is referred to as a right-of-way or a corridor. On behalf of NRLP, HONI will perform regular maintenance to maintain clearance distances between the energized circuits and the vegetation located on and adjacent to the transmission right-of-way. In Southern Ontario, vegetation maintenance is performed on clearing cycles of six years. Cycle lengths have been set to ensure that rights-of-way are in good condition and maintain a sustainable level of reliability between maintenance cycles. NRLP’s transmission line is also subject to NERC Reliability Standard FAC-003 entitled ‘Transmission Vegetation Management’, which requires NRLP to report all sustained outages caused by vegetation on 230kV circuits within NRLP’s control. Circumstances that are beyond the control of NRLP such as natural disasters and human activity such as logging are excluded. If vegetation management issues arise mid-cycle, HONI would undertake corrective action to resolve reliability and safety problems.

A summary of the planned maintenance activities and frequency of maintenance can be found in Table 3.

**Table 3: Summary of Planned Maintenance Activities**

| Asset | Maintenance | Frequency | Description |
|---|---|---|---|
| **Overhead Transmission Lines** | Helicopter Patrol | 1 year | High-speed patrol to identify major defects on overhead transmission line assets. |
| | Ground Patrol | 5 years | More detailed ground-based patrol to identify defects on overhead transmission line assets. |
| | Thermovision | 1 year | Identifies defective transmission line components by detecting their heat signature using infrared cameras. |
| **Transmission Rights of Way** | Line Clearing | 6 years | Consists of trimming tree branches and removing any unhealthy trees on the edge of or adjacent to the right-of-way that has the potential to exceed NRLP’s clearances to the overhead transmission lines. |
| | Brush Control | 6 years | Includes manual cutting, herbicide application and/or mechanical clearing to manage vegetation growth on the right-of-way to ensure adequate clearances and access to NRLP’s overhead transmission lines. |
| | Condition Patrol | 6 years | A mid-cycle working inspection to identify and mitigate any vegetation which requires maintenance prior to the next scheduled line clearing or brush control activity. |
| | Property Owner Notifications | 6 years | Prior to the execution of right-of-ways vegetation maintenance, HONI contacts all required adjacent property owners and external stakeholders to communicate maintenance plans. |
| | Annual Vegetation Patrol | 1 year | In accordance with NERC Standard FAC-003, NRLP is required to annually inspect all 230kV circuits. |

### 3.3.2 ASSET REPLACEMENT

NRLP’s planned replacement strategy is the same as HONI’s. Assets are replaced based on condition assessments. Once an asset condition is determined to be at EOL, it is scheduled and prioritized for replacement. In the case of material unplanned capital replacement, NRLP proposes utilizing a z-factor claim approach in accordance with Section 2.8.12 of the OEB Filing Requirements, if necessary.

## 3.4 SYSTEM CAPABILITY ASSESSMENT RENEWABLE ENERGY GENERATION (*OEB Filing Req. 5.3.4*)

The NRLP 230kV double circuit transmission line is operated in accordance with the planning criteria as part of the IESO-controlled grid based on the load, generation and import patterns. The NRLP circuits to allow for both the transfer of committed generating resources and the potential to enable new renewable resources in the Niagara region. If new generation requests emerge, the assessment of capacity need or limitation would be completed under the purview of the IESO as part of bulk system planning. At this time, there is no meaningful increase in the renewable energy generation connection forecast that is expected to affect NRLP's assets.

## 4.0 CAPITAL EXPENDITURE PLAN

This section provides the details of the overall plan that NRLP plans to undertake over the 2020 to 2024 period and other pertinent information regarding the elements of the planning process.

### 4.1 CAPITAL PLANNING PROCESS OVERVIEW *(OEB Filing Req. 5.4.1)*

On behalf of NRLP, HONI will complete an annual investment planning process to establish a plan that appropriately reflects operational needs, while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets.

### 4.2 CAPITAL AND OM&A EXPENDITURE SUMMARY (*OEB Filing Req. 5.4.2)*

Table 4 provides a summary of NRLP's Overall Plan. NRLP is not anticipating the need for any planned capital spending over the five-year horizon. NRLP is forecasting modest system OM&A expenditures in the test year. Further details are presented in Exhibit F, Tab 2, Schedule 1.

**Table 4: Overall Plan ($Millions)**

*OEB Appendix 2-AB*

| | Forecast | | | | |
|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 |
| **OEB Category** | **Test** | **Test** | **Test** | **Test** | **Test** |
| System Access | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| System Renewal | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| System Service | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| General Plant | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total Capital** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** |
| **System OM&A** | **0.52** | **0.53** | **0.54** | **0.55** | **0.55** |

**System OM&A includes Operations, Maintenance and Administration expenses related to NRLP's Service Level Agreement with HONI. System OM&A for 2021 to 2024 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1. It does not include the incremental expenses of the Managing Directors office and Insurance.*

### 4.3 JUSTIFYING CAPITAL EXPENDITURES (*OEB Filing Req. 5.4.3)*

This section (and corresponding OEB Appendix 2-AA) is not applicable, as NRLP is not anticipating the need for any planned capital spending over the five-year horizon.

# NIAGARA REINFORCEMENT ASSET VALUES

## 1. PURPOSE

In assessing the transfer of assets from Hydro One Networks Inc. to NRLP, the OEB made the following finding:

> *The OEB finds that the proposed transfer is reasonable and is not anticipated to have any negative effects. However, for greater clarity, the OEB notes that the leave to sell the NR Assets does not constitute an approval of the value of the NR Assets for the purpose of rates or any entitlement of NRLP to recover the full cost of the assets. The prudence of the cost of these assets will be determined by the OEB in the future transmission rate proceedings.*

This schedule is provided to demonstrate the prudence of the costs of the assets and why NRLP is requesting to recover the full cost.

## 2. PROJECT BACKGROUND

Hydro One Networks Inc. (“HONI”) originally obtained leave to construct approval on July 8, 2005, to complete the Niagara Reinforcement Project (“NRP” or “the Project”), with an estimated cost of $116 million and a planned in-service date of summer 2007. The approved project plan included:

- construction of a new 76 km double circuit 230 kV transmission line between Allanburg Transformer Station (“TS”) and Middleport TS;
- upgrades to Middleport TS; and
- a provision that would enable a section of one new 230 kV line, from Caledonia TS to St. Ann’s Junction) to be operated at 115 kV as an emergency back-up supply for Dunnville TS.

The benefits the Niagara Reinforcement Project brings to the transmission system are significant. As outlined during the original approval and reinforced in Hydro One's letter to the OEB on April 4, 2018 ("the Project Update Letter"), the transmission facilities were intended to alleviate transmission constraints at the Queenston Flow West ("QFW") transmission interface.

The Niagara Interface and QFW interface are critical corridors for moving electricity supply in Ontario. These interfaces allow for the transmission of clean, hydroelectric power generated in the Niagara region and they facilitate the importing and exporting of power between New York state and Ontario. The existing Niagara transmission capability can limit imports via the New York interties and, at times, can constrain renewable generation in Niagara. Limitations on the 230kV Niagara transmission capability restrict any significant new renewable or clean energy development in the Niagara area. In the last Large Renewable Program ("LRP") procurement, the Niagara area was a restricted zone for prospective projects. The NRP increases the number of 230kV circuits connecting the Niagara area system to the rest of Ontario from five to seven. The IESO's 18-month Outlook "An Assessment of the Reliability and Operability of the Ontario Electricity System" released on March 21, 2018, confirms that transmission congestion continues to restrict generation in the Niagara region and that the NRP project once completed, will increase the transfer capability to the rest of the Ontario system by approximately 700 MW.

NRP will allow for more cost-effective and timely refurbishment of the critical Sir Adam Beck II transmission station, which connects the Beck generation supply as well as the interconnections with New York to the Ontario grid. Because of the high utilization and criticality of the 230kV Niagara transmission circuits, there are significant limitations for outages that result in complex and lengthy refurbishment work at the Beck II station.

NRP will significantly alleviate such limitations such as outage durations at Middleport TS.

The NRP is also expected to provide additional value to transmission ratepayers by reducing line losses on the QFW interface by between 10,500 MWh and 22,750 MWh on an annual basis.

### 2.1 DELAY AND RESTART OF PROJECT

As discussed in the Project Update Letter, in the summer of 2006 when the project was near completion, an unforeseen land claim dispute in the Caledonia area, unrelated to the project, between a developer and a First Nations interest, resulted in a blockade of the land surrounding the worksite. The decision was made to suspend work on the project while the occupation remained in place. This disruption prevented a substantial section of the line around Caledonia from being completed within the project timelines and therefore the line could not be placed into service as originally planned.

The dispute at the site lasted several years and what became clear was that a new agreement was necessary with the First Nations communities that were affected by the line. Discussions with the local communities took place to forge an agreement that would allow the project to move ahead to completion. Ultimately, those negotiations were successful and a beneficial partnership agreement was reached with the neighbouring communities. Construction activities recommenced on the Project in 2018 and the line was placed into service on August 30, 2019.

## 3. COST IMPACTS OF DELAY

As anticipated in the Project Update Letter, and now confirmed with actual expenditures, the total cost of the project has exceeded the original approval. Table 1 shows the changes to the total project value over time.

**Table 1 – Chronology of Project Value for NRP**

| Reference Point | Project Value | (Planned) In-service Date |
|---|---|---|
| **Leave to Construct – Jul 2005** | $116.0 million | Summer 2007 |
| **Project Update Letter – Apr 2018** | $129.2 million | May 2019 |
| **Current Application** | $135.2 million | August 30, 2019 |

## 3.1 INFLATION

A primary reason for the increase since the 2005 estimate is simple inflation. Costs, including the price of the various inputs to the project such as labour and materials, would normally and reasonably be expected to increase over the 14 years between the original estimate and the final construction cost. Hydro One was able to reuse certain assets and negotiated favourable terms with its contractor to minimize cost increases due to inflation.

## 3.2 PROJECT CHALLENGES

Certain other cost pressures emerged on the project. Upon restarting the work, in addition to the completion of the remaining sections of the original project, construction crews had to address a number of additional items that put upward pressure on costs. These items included:

- tower and line rework was needed on some previously installed assets in certain locations around Caledonia, due to vandalism over the last 13 years;
- stringing of 8.5 km of transmission line was required to connect to the conductor termination points;
- material necessary to complete the project (lattice structures, insulators) needed to be repurchased; and,
- protection changes to the terminal stations were necessary as a result of Thorold GS being connected to one of the circuits (Q26M) in 2010.

### 3.3 ALLOCATED FUNDS USED DURING CONSTRUCTION

Once it became clear that the project delay was long term, Hydro One applied for and received approval to include an amount in its revenue requirement for simple interest on the outstanding construction balance of the project[1]. During this time the accumulation of AFUDC was suspended and no such costs are being sought for recovery in this Application.

In 2018, the project was restarted and the inclusion of simple interest in Hydro One's revenue requirement was halted. The normal collection of AFUDC costs in the project was reinstituted and those costs have been recorded since January 2018.

In January 2019, after several months of work and as the project was nearing completion, a new blockade was placed on the site. Work on the project was once again halted out of respect for the safety of workers and the general public. Several meetings took place but a suitable agreement to end the blockade could not be reached. Facing yet another long and protracted delay to the project, Hydro One sought and successfully received injunctive relief from the Court of Ontario and work resumed in July 2019. Nonetheless, this delay caused an additional accumulation of AFUDC for approximately 6 months or approximately $3 million. Table 2 details the annual AFUDC values that contribute to the costs being sought for recovery in this application.

[1] See EB-2006-0501

**Table 2 – Annual AFUDC Breakdown**

| Year | AFUDC ($M) |
|---|---|
| **Up to 2006** | 5.02 |
| **2007- 2017** | 0.00 |
| **2018** | 4.37 |
| **2019** | 3.01 |
| **Total** | 12.40 |

## 3.4 FINAL PROJECT COSTS TO BE RECOVERED

The Project Update Letter originally anticipated that project costs were going to be $129.2 million, or 11% over the previously approved amount from the leave to construct application with an in-service date of May 2019. On September 3rd, 2019, in accordance with the conditions of approval, Hydro One informed the OEB that the Niagara Reinforcement Project had been placed in-service on August 30, 2019. The total cost for the NRP is $135.2 million. As documented in Exhibit C, Tab 1, Schedule 1, the in-service additions that NRLP is seeking to include in its rate base through this application are $119.4 million. The remaining $15.8 million of project costs be added to HONI's Rate Base. This residual amount of assets was not included in the transfer to NRLP and is primarily related to station assets and Optical Ground Wire, which will continue to be owned by HONI.

HONI submits that the incremental cost to complete the project is reasonable given the unexpected delay in the project, the challenges faced by the project at restart, and the additional interest incurred due to the 2019 blockade.

HONI also submits that the expenditures were prudent given the significant benefits to Ontario's ratepayers from (a) providing increased supply capacity, (b) reducing transmission line losses and (c) facilitating outage reliability in the Niagara region.

# RATE BASE

## 1. INTRODUCTION

This Exhibit provides a forecast of NRLP's rate base for the 2020 test year and a detailed description of each of the components.

The rate base underlying the revenue requirement for the Test Year includes a forecast of net utility plant, calculated on a mid-year average basis. No working capital has been requested, as discussed in section 4 below.

## 2. UTILITY RATE BASE

Utility rate base for the Test year is filed at Exhibit C, Tab 2, Schedule 1. The calculation of Net Utility Plant is provided at Exhibit C, Tab 2, Schedule 4.

NRLP's forecast rate base for the 2019 Bridge year and 2020 Test year is shown in Table 2.

**Table 2 - Transmission Rate Base ($ Millions)**

| Description | Bridge | Test |
|---|---|---|
| | 2019 | 2020 |
| Mid-Year Gross Plant | 59.72 | 119.43 |
| Mid-Year Accumulated Depreciation | (0.40) | (1.59) |
| **Mid-Year Net Plant** | **59.32** | **117.84** |
| Cash Working Capital | 0.00 | 0.00 |
| Materials and Supply Inventory | 0.00 | 0.00 |
| **Transmission Rate Base** | **59.32** | **117.84** |

A historical and bridge year continuity of total fixed assets is not applicable given that NRLP is a new transmitter and all NRLP in-service additions occurred in 2019.

## 3. CASH WORKING CAPITAL

In 2013, B2M LP retained Navigant Consulting Inc. to undertake a lead-lag study on its working capital requirements. The study found that the flows of revenue and expenses substantially offset each other, resulting in an approximately zero requirement for cash working capital. Further details may be found in B2M LP's previous transmission rate application (EB-2015-0026) at Exhibit D1, Tab 1, Schedule 2. Despite not having undertaken an independent assessment, NRLP proposes that it also has approximately zero working capital requirement, analogous to that of B2M LP.

NRLP's expenses and revenues are planned to be generally synchronized such that no working capital has been requested in this Application.

## 4. IN-SERVICE ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use.

Given the asset was recently placed into service and that the asset is new, NRLP expects the asset condition to remain good and has no plans to make any in-service additions during the rate period.

**NRLP**
Statement of Average Rate Base
Bridge Year (2019) and Test Year (2020)
Year Ending December 31
($ Millions)

| Line No. | Particulars | 2019 | 2020 |
|---|---|---|---|
| | Electric Utility Plant | | |
| 1 | **Gross plant** | | |
| | Transmission Corridor Land and Rights | 1.00 | 1.00 |
| | Towers and Fixtures | 78.43 | 78.43 |
| | Conductors and Devices | 40.00 | 40.00 |
| | Roads and Trails | 0.00 | 0.00 |
| | **Total Gross Plant** | 119.43 | 119.43 |
| 2 | Accumulated Depreciation | 0.79 | 2.38 |
| 3 | Net plant in-service | 118.64 | 117.05 |
| 4 | Average net plant for rate base | 59.32 | 117.84 |
| 5 | Construction work in progress | 0.00 | 0.00 |
| 6 | Average net utility plant | $ 59.32 | $ 117.84 |
| | Working Capital | | |
| 7 | Cash working capital | 0.00 | 0.00 |
| 8 | Materials and Supplies Inventory | 0.00 | 0.00 |
| 9 | Total working capital | 0.00 | 0.00 |
| 10 | Total rate base | $ 59.40 | $ 117.80 |

**NRP LP**
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical, Bridge (2019) & Test (2020) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out and Other | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Historic | | | | | | | | |
| 1 | 2015 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | 2016 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | 2017 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | 2018 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Bridge | | | | | | | | |
| 5 | 2019 | 0.00 | 0.79 | 0.00 | 0.00 | 0.00 | 0.79 | 0.40 |
| Test | | | | | | | | |
| 6 | 2020 | 0.79 | 1.59 | 0.00 | 0.00 | 0.00 | 2.38 | 1.59 |

**NRLP**

Continuity of Property, Plant and Equipment
Historical (2015 - 2018), Bridge (2019) & Test (2020) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

| Line No. | Year | Opening Balance | Additions | Retirements | Sales | Transfers In/Out | Closing Balance | Average |
|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| Bridge | | | | | | | | |
| 1 | 2015 | - | - | - | - | - | - | - |
| 2 | 2016 | - | - | - | - | - | - | - |
| 3 | 2017 | - | - | - | - | - | - | - |
| 4 | 2018 | - | - | - | - | - | - | - |
| Bridge | | | | | | | | |
| 5 | 2019 | - | 119.43 | - | - | - | 119.43 | 59.72 |
| Test | | | | | | | | |
| 6 | 2020 | 119.43 | - | - | - | - | 119.43 | 119.43 |

Witness: Samir Chhelavda

NRLP

Continuity of Depreciation and Amortization by Asset Type
Bridge 2019, Test 2020 and 2021 to 2024
Year Ending December 31
($ millions)

| Year | Description 3 | Cost: Opening Balance | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|---|
| 2019 | Land | - | - | - | - | - | - |
| | Land rights | - | 1.00 | - | 0.00 | 0.00 | 1.00 |
| | Buildings and fixtures | - | - | - | - | - | - |
| | Towers and fixtures | - | 78.43 | - | 0.50 | 0.50 | 77.93 |
| | Overhead conductors and devices | - | 40.00 | - | 0.29 | 0.29 | 39.71 |
| | Roads and trails | - | - | - | - | - | - |
| | Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | | - | | | - |
| | **Sub-Total** | **-** | **119.43** | **-** | **0.79** | **0.79** | 118.64 |
| | **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| | ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| | **Total PP&E** | **-** | **119.43** | **-** | **0.79** | **0.79** | 118.64 |

| Year | Description 3 | Cost: Opening Balance | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|---|
| 2020 | Land | - | - | - | - | - | - |
| | Land rights | 1.00 | 1.00 | 0.00 | 0.01 | 0.01 | 0.99 |
| | Buildings and fixtures | - | - | - | - | - | - |
| | Towers and fixtures | 78.43 | 78.43 | 0.50 | 1.00 | 1.51 | 76.92 |
| | Overhead conductors and devices | 40.00 | 40.00 | 0.29 | 0.58 | 0.86 | 39.14 |
| | Roads and trails | - | - | - | - | - | - |
| | Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | | - | | | - |
| | **Sub-Total** | **119.43** | **119.43** | **0.79** | **1.59** | **2.38** | 117.05 |
| | **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| | ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| | **Total PP&E** | **119.43** | **119.43** | **0.79** | **1.59** | **2.38** | 117.05 |

NRLP

Continuity of Depreciation and Amortization by Asset Type
Bridge 2019, Test 2020 and 2021 to 2024
Year Ending December 31
($ millions)

**2021**

| | Cost | | Accumulated Depreciation | | | |
|---|---|---|---|---|---|---|
| **Description 3** | **Opening Balance** | **Closing Balance** | **Opening Balance** | **Additions** | **Closing Balance** | **Net Book Value** |
| Land | - | - | - | - | - | - |
| Land rights | 1.00 | 1.00 | 0.01 | 0.01 | 0.02 | 0.98 |
| Buildings and fixtures | - | - | - | - | - | - |
| Towers and fixtures | 78.43 | 78.43 | 1.51 | 1.00 | 2.51 | 75.92 |
| Overhead conductors and devices | 40.00 | 40.00 | 0.86 | 0.58 | 1.44 | 38.56 |
| Roads and trails | - | - | - | - | - | - |
| Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | - | | | - |
| **Sub-Total** | **119.43** | **119.43** | **2.38** | **1.59** | **3.97** | 115.46 |
| **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| **Total PP&E** | **119.43** | **119.43** | **2.38** | **1.59** | **3.97** | 115.46 |

**2022**

| | Cost | | Accumulated Depreciation | | | |
|---|---|---|---|---|---|---|
| **Description 3** | **Opening Balance** | **Closing Balance** | **Opening Balance** | **Additions** | **Closing Balance** | **Net Book Value** |
| Land | - | - | - | - | - | - |
| Land rights | 1.00 | 1.00 | 0.02 | 0.01 | 0.03 | 0.97 |
| Buildings and fixtures | - | - | - | - | - | - |
| Towers and fixtures | 78.43 | 78.43 | 2.51 | 1.00 | 3.51 | 74.92 |
| Overhead conductors and devices | 40.00 | 40.00 | 1.44 | 0.58 | 2.02 | 37.98 |
| Roads and trails | - | - | - | - | - | - |
| Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | - | | | - |
| **Sub-Total** | **119.43** | **119.43** | **3.97** | **1.59** | **5.56** | 113.87 |
| **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| **Total PP&E** | **119.43** | **119.43** | **3.97** | **1.59** | **5.56** | 113.87 |

NRLP

Continuity of Depreciation and Amortization by Asset Type
Bridge 2019, Test 2020 and 2021 to 2024
Year Ending December 31
($ millions)

**2023**

| Description 3 | Cost: Opening Balance | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|
| Land | - | - | - | - | - | - |
| Land rights | 1.00 | 1.00 | 0.03 | 0.01 | 0.04 | 0.96 |
| Buildings and fixtures | - | - | - | - | - | - |
| Towers and fixtures | 78.43 | 78.43 | 3.51 | 1.00 | 4.52 | 73.91 |
| Overhead conductors and devices | 40.00 | 40.00 | 2.02 | 0.58 | 2.59 | 37.41 |
| Roads and trails | - | - | - | - | - | - |
| Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | - | | | - |
| **Sub-Total** | **119.43** | **119.43** | **5.56** | **1.59** | **7.15** | 112.28 |
| **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| **Total PP&E** | **119.43** | **119.43** | **5.56** | **1.59** | **7.15** | 112.28 |

**2024**

| Description 3 | Cost: Opening Balance | Cost: Closing Balance | Accumulated Depreciation: Opening Balance | Accumulated Depreciation: Additions | Accumulated Depreciation: Closing Balance | Net Book Value |
|---|---|---|---|---|---|---|
| Land | - | - | - | - | - | - |
| Land rights | 1.00 | 1.00 | 0.04 | 0.01 | 0.05 | 0.95 |
| Buildings and fixtures | - | - | - | - | - | - |
| Towers and fixtures | 78.43 | 78.43 | 4.52 | 1.00 | 5.52 | 72.91 |
| Overhead conductors and devices | 40.00 | 40.00 | 2.59 | 0.58 | 3.17 | 36.83 |
| Roads and trails | - | - | - | - | - | - |
| Load Management Controls Customer Premises | - | - | - | - | - | - |
| | | | - | | | - |
| **Sub-Total** | **119.43** | **119.43** | **7.15** | **1.59** | **8.74** | 110.69 |
| **Less Socialized Renewable Energy Generation Investments (input as negative)** | | | | | - | - |
| ***Less Other Non Rate-Regulated Utility Assets (input as negative)*** | | | | | - | - |
| **Total PP&E** | **119.43** | **119.43** | **7.15** | **1.59** | **8.74** | 110.69 |

# PERFORMANCE MEASURES

## 1. INTRODUCTION

Given the nature of NRLP's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. NRLP's assets consist of a single 230kV double circuit transmission line between the Allanburg and Middleport Transmission Stations, but do not include any terminal breakers or other operable assets. The demarcation point of each of the circuits is at a tower outside of the station, as noted in Exhibit B, Tab 1, Schedule 1. NRLP does not have any customer delivery points (or meter assets), which are the basis of interruption-based reliability performance measures like SAIDI and SAIFI. In addition to these operating characteristics, the life-cycle portfolio also detracts from meaningful comparisons. NRLP's single transmission line is relatively new; whereas other transmitters own a portfolio of assets that traverse the various stages of asset life.

For NRLP to adopt a slate of performance measures similar to other transmitters would not readily provide meaningful comparisons. On this basis, NRLP proposes that System Average Interruption Frequency and System Average Interruption Duration not be measured. Furthermore, NRLP has no customers, so no Customer Focus measures have been proposed.

## 2. PERFORMANCE MEASURES

NRLP is proposing to track and demonstrate its performance by utilizing the same measures proposed for B2M LP in its recent application (EB-2019-0178). Filing a common set of measures as B2M LP serves to accomplish the following:

a) Provide meaningful comparisons in asset performance with a similar transmitter,
b) Minimize ratepayer costs by optimizing administrative costs through a single set of items, and,
c) Provide the Board and customers with confidence that NRLP is meeting its five-year plan as described in this Application.

The performance measures will be tracked annually, and the results of this tracking will be reported to the Board at the next proceeding. A description of the performance measures is provided in Appendix A of this schedule.

## Appendix A – Description of the Performance Measures

***Average System Availability***

"System Availability" is a measure of the extent to which the transmission line(s) are available for use within the system. For the purposes of quantifying this metric, the cause of the forced outages that would contribute to the unavailability of the transmission lines would be limited to factors affecting assets owned by NRLP as opposed to terminal equipment, owned by Hydro One, which could also cause the transmission line(s) to be removed from service.

$$= \left[ 1 - \left( \frac{\sum_{i=1}^{N_L} F_{L_i}}{T_L} \right) \right] \times 100\%$$

- $F_{Li}$ is the annual forced outage duration in hours due to transmission line-related outages of circuit $L_i$.
- $T_L$ is the inventory (expressed in 100 km-hours) of all in-service transmission circuits.
- $N_L$ is the total number of in-service transmission circuits

***NERC Vegetation Compliance***

NERC Vegetation Compliance is a measure of the extent to which NRLP is compliant with NERC's Standard FAC-003-02 'Transmission Vegetation Management'. NERC developed a Transmission Vegetation Management Standard with the objective to prevent vegetation-related outages which could contribute to a cascading grid failure, especially under heavy electrical loading conditions. Each transmission owner is required to have a transmission vegetation management program designed to control vegetation on the active transmission line right-of-way in accordance with the requirements in NERC Standard FAC-003-02. Compliance with the Standard is mandatory and enforceable.

***Return on Equity***

Return on Equity compares the profitability of the Applicant over a period compared to the amount of equity invested by the partners. The biggest impact on ROE for NRLP is related to revenue variances caused generally by changes in weather compared to budget.

Using the Audited Statements, the ROE is calculated by dividing the Net Income (less extraordinary non-operating items such as startup cost reimbursement) by the Partners' Equity.

# REVENUE REQUIREMENT

## 1. SUMMARY OF REVENUE REQUIREMENT

NRLP follows standard regulatory practice and has calculated its revenue requirement as follows:

**Table 1 - Revenue Requirement ($ Millions)**

| Components | 2020 | Reference |
|---|---|---|
| OM&A | 0.85 | Exhibit F, Tab 1, Schedule 1 |
| Depreciation | 1.59 | Exhibit F, Tab 5, Schedule 1 |
| Income Taxes | 0.06 | Exhibit F, Tab 6, Schedule 1, Attachment 1 |
| Return on Capital | 6.89 | Exhibit G, Tab 1, Schedule 1 |
| **Base Revenue Requirement** | **9.39** | |
| Deduct External Revenues and Other[2] | 0.0 | |
| Add/(Deduct) Regulatory Accounts Disposition/Foregone/Other | 6.38 | Exhibit H, Tab 1, Schedule 1 |
| **Rates Revenue Requirement** | **15.77** | |

The above Revenue Requirement is the amount required by NRLP to achieve its business objectives, responsible stewardship of a safe and reliable system, and impact on rates. The proposed Revenue Requirement is a reflection of NRLP's commitment to operating at the lowest practical cost.

## 2. CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

**Table 2 - OM&A Expense ($ Millions)***

| | **2020** |
|---|---|
| Service Level Agreement Costs | 0.53 |
| Incremental Expenses | 0.32 |
| **Total OM&A** | **0.85** |

** Exhibit F, Tab 2, Schedule 1*

**Table 3 - Depreciation and Amortization Expense ($ Millions)***

| | **2020** |
|---|---|
| Depreciation | 1.59 |
| **Total Expense** | **1.59** |

**Exhibit F, Tab 5, Schedule 1*

**Table 4 - Corporate Income Taxes ($ Millions)***

| | **2020** |
|---|---|
| Regulatory Taxable Income | (1.76) |
| Income Tax Rate | 26.5% |
| **Corporate Income Tax** *(Does not apply if less than zero)* | **-0.55** |
| | |
| Accounting Income | 2.39 |
| OCMT Rate | 2.7% |
| **Net Income Taxes (OCMT)** | **0.06** |

** Exhibit F, Tab 6, Schedule 1*

**Table 5 - Return on Capital ($ Millions)***

| | **2020** |
|---|---|
| Return on Debt | 2.65 |
| Return on Equity | 4.23 |
| **Return on Capital** | **6.89** |

** Exhibit G, Tab 1, Schedule 1*

## 3. REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

There is no previous revenue requirement for NRLP, therefore this section of the Application is not applicable.

**NRLP**
Calculation of Base Revenue Requirement (2020)
Year Ending December 31
($ Millions)

| Line No. | Particulars | | Test 2020 |
|---|---|---|---|
| | | | (a) |
| | Cost of Service | | |
| 1 | Operating, maintenance & administrative | $ | 0.85 |
| 2 | Depreciation | | 1.59 |
| 3 | Income taxes | | 0.06 |
| 4 | Cost of service excluding return on capital | $ | 2.50 |
| 5 | Return on capital | | 6.89 |
| 6 | Base revenue requirement | $ | 9.39 |

# OPERATING COSTS SUMMARY

## 1. INTRODUCTION

This Exhibit presents an overview of NRLP's operating costs and includes the following elements, for which the overall costs are shown in Table 1 below:

- Operation, Maintenance and Administrative ("OM&A"),
- Depreciation and Amortization, and
- Income Taxes.

**Table 1 - Operating Costs ($ Millions)**

| Description | Bridge Year | Test Year |
|---|---|---|
| | **2019** | **2020** |
| OM&A | 0.28 | 0.85 |
| Transition Costs | 1.71 | 0.0 |
| Depreciation and Amortization | 0.79 | 1.59 |
| Income Taxes | 0.03 | 0.06 |
| **Total Operating Costs**[1] | **2.81** | **2.50** |
| **Operating Cost excluding One-Time Transition Costs** | **1.10** | **2.50** |

The proposed operating costs for the 2020 Test Year are forecast to be $2.50 million, an increase of $1.40 million compared to the 2019 Bridge year forecast without one-time transition costs. This increase is due to higher OM&A and Depreciation expenses that reflect a full year of operation, as documented in Exhibit F, Tab 2, Schedule 1 and Exhibit F, Tab 5, Schedule 1, respectively.

## 2. KEY ELEMENTS OF OPERATING COSTS

NRLP's operating costs forecast has been developed to sustain the safe and reliable operation of its transmission assets.

### 2.1 OPERATION, MAINTENANCE AND ADMINISTRATIVE ("OM&A")

NRLP is managed by its general partner, Hydro One Indigenous Partnerships GP Inc. ("HOIP GP"), which retains Hydro One Networks ("HONI"), under a Service Level Agreement, to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support as outlined in Exhibit F, Tab 3, Schedule 1.

OM&A expenses are derived based upon the various work programs and functions performed by or on behalf of the Partnership. The estimated total OM&A expense is $0.85 million in 2020. Further details on the OM&A costs are provided in Exhibit F, Tab 2, Schedule 1.

### 2.2 DEPRECIATION AND AMORTIZATION

The depreciation expense for NRLP in this Application is supported by recommendations that Foster Associates Inc. made on the appropriate depreciation rates for HONI Transmission in support of its 2020 to 2022 Rate Application (EB-2019-0082). This methodology is consistent with that approved for use by B2M LP and HONI Transmission in previous proceedings. The estimated depreciation expense is $1.59 million in 2020. Further details are provided in Exhibit F, Tab 5, Schedule 1.

### 2.3 INCOME TAXES

Under the *Income Tax Act*, a partnership is not taxable but is required to compute its taxable income, which is then allocated to its partners. The estimated Income Tax expense that will be required to be paid by the partners from the income generated in

NRLP is $0.06 million in 2020. Details of the calculation of the Income Tax expense are shown in Exhibit F, Tab 6, Schedule 1.

# SUMMARY OF OM&A EXPENDITURES

## 1. SUMMARY OF OM&A EXPENDITURES

The proposed Operation, Maintenance, and Administration ("OM&A") expenses represent the work required to meet public and employee safety objectives, maintain transmission reliability, and to comply with regulatory requirements, environmental requirements and Government direction. Key components in the build-up of OM&A requirements include:

- Service Level Agreement with Hydro One Networks ("HONI"), and
- Ongoing Incremental Expenses of the Partnership.

Table 1 presents the required funding for OM&A in the 2020 Test Year for each of these key components. Overall, NRLP's OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario. This relates primarily to the characteristics of the assets that it owns. NRLP owns a 230kV double-circuit transmission line that requires periodic vegetation management expenses and operating services costs but otherwise very little given that the company owns no station assets. Additionally, this type of asset is extremely reliable and has a low probability of fault or other incident requiring corrective maintenance or repair expenditures.

**Table 1 - Summary of OM&A ($ Millions)**

| Description | Test 2020 Forecast |
|---|---|
| Service Level Agreement Costs | 0.52 |
| Incremental Expenses | 0.31 |
| **Total OM&A** | **0.83** |

The proposed OM&A spending for the 2020 Test year is forecast to be $0.83 million. More details on the future spending on each of these components are included below.

# 2. KEY COMPONENTS OF THE OM&A EXPENDITURES

## 2.1 SERVICE LEVEL AGREEMENT COSTS

The bulk of the OM&A expenses required to satisfy the obligation and objectives of the company arise as the result of a Service Level Agreement between HONI and NRLP.

The costs for these services are estimated using the HONI fully-allocated costs incurred to perform the services outlined in the Service Level Agreement. Table 2 presents the required funding for these services in the 2020 Test Year. Further details on these services are provided in the following sections.

**Table 2 - Total Service Level Agreement Costs ($ Millions)**

| Description | Test 2020 Forecast |
|---|---|
| Operations and Maintenance Expenses | 0.32 |
| Administrative and Corporate Expenses | 0.20 |
| **Total Service Level Agreement Costs** | **0.52** |

### 2.1.1 OPERATION AND MAINTENANCE EXPENSES

The Operation and Maintenance expenses relate to the Operating Services and Maintenance Services performed by HONI, on behalf of NRLP. Examples of the services received are listed below:

**Operating Services:**

- Monitoring/Control of the transmission system, including alarm monitoring, asset monitoring, and minor control;
- Asset Operation within HONI-prescribed limits including the application of HONI equipment directives and switching on HONI’s transmission system to regulate NRLP 's transmission system;

- Emergency Response to transmission system events, including response to IESO-directed emergency actions, and implementation of load shedding;
- Outage Processing including scheduling, planning, and submitting to IESO;
- Crew Dispatching, including 24/7 assessment, contacting, and dispatching;
- Record Maintenance including retention of logged items, retention of SCADA information, and trip reports; and
- Power System IT Support of the power system applications used by operators.

**Maintenance Services:**

- Overhead Transmission Lines maintenance including thermovision, helicopter and ground patrols; and
- Transmission Right-of-Way maintenance, including mandatory annual NERC vegetation patrols, line clearing, brush control, condition patrol and property owner notifications.

Further details on the maintenance services are presented in NRLP's Transmission System Plan in Attachment 1 to Exhibit B, Tab 1, Schedule 3.

### 2.1.2 ADMINISTRATIVE AND CORPORATE EXPENSES

The Administrative and Corporate Expenses include the costs arising from the support functions provided by HONI to NRLP for administrative services and systems. The investment in those systems and the cost of their operation are incurred by HONI but are allocated to Hydro One Inc. and its affiliates through a cost allocation methodology.

This methodology lowers costs for all of the Hydro One subsidiaries by providing access to a sophisticated administration infrastructure at a lower cost than if each built its own unique and independent system. This sharing of the costs for a unified infrastructure benefits ratepayers through lower rates and has been accepted by the Board in numerous previous proceedings, including B2M LP's 2015 to 2019 Transmission Rates Application (EB-2015-0026). Further details on the common corporate costs and cost allocation methodology are provided in Exhibit F, Tab 4, Schedule 1.

## 2.2 INCREMENTAL EXPENSES

There are certain functions that must be executed by NRLP to meet its obligations and objectives that are not supported by the Service Level Agreement with HONI. Table 3 presents the required funding in the 2020 Test Year. Further details on these functions are provided in the following sections.

**Table 3 - Total Incremental Expenses ($ Millions)**

| Description | Test 2020 Forecast |
|---|---|
| Insurance | 0.05 |
| Managing Director's Office | 0.26 |
| **Total Incremental Expense** | **0.31** |

### 2.2.1 INSURANCE

NRLP is obligated, by its partnership agreement and by good utility practice, to maintain an appropriate level of insurance to protect its assets, its owners and its customers from catastrophic loss. NRLP is fortunate to be able to leverage the existing Hydro One Inc. insurance policies, rather than procuring insurance protection unilaterally. This results in considerable savings for NRLP. The annual premiums for this insurance are about $0.05 million.

### 2.2.2 MANAGING DIRECTOR'S OFFICE

The partnership has a Managing Director, who is empowered to oversee and operate the partnership. The duties of this person include:

- Monitoring and ensuring that the terms and conditions of the partnership agreement are fulfilled;
- Working with employees from HONI and other entities to ensure that the Applicant and its assets are properly maintained and administered;
- Managing and Chairing Advisory Committee meetings with the partners on a regular basis, as spelled out in the partnership agreement;
- Ensuring that the partners are kept well informed and advised of the partnership's operations, and educated on what it means to be a transmission owner and operator in Ontario;
- Authorizing the disbursement of funds by the partnership to meets its obligations and expenses;
- Instituting communications with communities and the public at large, through meetings, websites and other media;
- Representing the partnership with various stakeholders at hearings, industry events and other situations; and
- Any and all other duties that may be required to represent the partnership and effectively support its operations.

To complete these tasks, the Managing Director’s Office is provided with an annual budget for things such as salary, office, communication, and other expenses that may be required. The total Managing Director’s Office expense included in the 2020 Test year is $0.26.

# AFFILIATE SERVICE AGREEMENTS

## 1. INTRODUCTION

NRLP is a limited partnership whose general partner is Hydro One Indigenous Partnerships GP Inc. (“HOIP”), an affiliate of Hydro One Networks Inc. (“HONI”). To comply with the Affiliate Relationships Code (“ARC”), provision of contracted services must be pursuant to service agreements. This Exhibit discusses the agreements between NRLP and HONI for operations services, maintenance services, and common administrative and corporate services.

## 2. DEVELOPMENT OF THE SERVICE LEVEL AGREEMENT

NRLP and HONI identified the nature of the services required for the safe and prudent operation of NRLP’s transmission assets in accordance with good utility practice. An Agreement for Operations and Management Services (“the Agreement”), dated September 18, 2019, capturing these requirements was reviewed and approved by each company’s accountable officer for an initial term of five years.

## 3. TERMS AND CONDITIONS

In accordance with the Applicant’s Transmission Licence, the ARC, and all other applicable codes, rules, orders and decisions of the Board, the Agreement describes the terms and conditions of the services that HONI provides to NRLP. These include the provisions of operations and management services, fees and taxes, invoicing and payment, budgets, accounts and right to audit, liability and force majeure events, dispute resolution procedures, confidentiality and intellectual property, and term and termination of the agreement. More details on the key clauses are provided below.

### 3.1 PROVISION OF OPERATIONS AND MANAGEMENT SERVICES

The Agreement addresses the provision by HONI to NRLP of operations, maintenance, and certain common administrative and corporate services. A description of the services contained in the Agreement is provided in Table 1.

**Table 1 - Service Level Agreement – 2020 to 2024**

| Services Provider | Services Recipient(s) | Description of Services |
|---|---|---|
| Hydro One Networks Inc. | NRLP | ***a) Operations Services*** – monitoring and control of the Transmission System, in accordance with the requirements of NRLP's Transmission Licence and all services required to fulfill all of NRLP's obligations under its Connection Agreement and the IESO-NRLP operating requirements. |
| Hydro One Networks Inc. | NRLP | ***b) Maintenance Services*** – all maintenance, repair and refurbishment services, in accordance with the requirements of NRLP's Transmission Licence and all services required to fulfill all of NRLP's obligations under its Connection Agreement and the IESO-NRLP operating requirements. |
| Hydro One Networks Inc. | NRLP | ***c) Administrative and Corporate Services*** – some corporate and administrative services provided by HONI, including finance and regulatory support, tax advice and returns preparation, treasury, communications and government relations, legal advice, real estate support, corporate security services, and First Nations support. |

### 3.2 FEES

Pursuant to the ARC, where a utility provides a service, resource, product or use of an asset to an affiliate, the utility shall charge no less than the greater of (i) the market price of that service, product, resource or use of asset, or (ii) the utility's fully-allocated cost to provide that service, product, resource or use of asset. In purchasing a service, resource, product or use of an asset from an affiliate, a utility shall pay no more than the market price for that service, product, resource or use of an asset. The level of costs for NRLP's services was determined in accordance with the principles above.

### 3.3 BUDGETS, ACCOUNTS AND RIGHT TO AUDIT

HONI will provide NRLP/HOIP with a proposed annual operating, maintenance and capital improvement budget for NRLP for the subsequent fiscal year at least 60 days prior to the commencement of the next fiscal year. The NRLP annual budget is accompanied by an annual operating plan prepared by HONI. HOIP notifies HONI, within 30 days after receipt of the budget, of any issues with respect to such proposed budget, and the two parties must cooperate with each other in developing a mutually acceptable budget for NRLP within the next 30 days.

HONI and HOIP agree that the budget may be amended from time to time by mutual agreement to reflect revisions necessitated by circumstances such as changes in applicable laws, additions or deletions to the scope of the services, emergencies and force majeure events.

If HONI becomes aware that the costs of services for the current fiscal year may exceed the budget by 5% or more, HONI must promptly notify HOIP of such anticipated budget overrun and provide HOIP with a proposed amendment to the budget.

HOIP must notify HONI within 30 days after receipt of HONI's proposed budget amendment of any issues, and the parties must cooperate with each other in developing a mutually acceptable amendment to the budget. Except in the case of an emergency, HONI is not allowed to perform any services without the prior approval of HOIP, if such services would result in a cost overrun.

In the event of an accident or emergency relating to the NRLP assets, HONI may take action to address the situation without obtaining approval from HOIP. This may result in spending funds deemed by HONI to be reasonably necessary under the circumstances. As promptly and as reasonably practicable after HONI establishes control over such accident or emergency, HONI must furnish HOIP with a reasonably detailed written description of the accident or emergency and the manner in which such accident or emergency was handled by HONI. As well, NRLP must pay HONI for the reasonable costs as incurred.

Except in the case of an emergency, HONI must perform all services in accordance with the annual operating plan accompanying the budget. HONI and HOIP agree to keep all necessary and proper accounts and records relating to services provided by HONI, and these accounts and records shall be open to audit and inspection for a period of six years.

## 3.4 DISPUTE RESOLUTION PROCEDURE

If the parties have a dispute under the agreement that cannot be resolved by a conference of their respective senior officers, a written notice outlining the specifics of the dispute will be passed to the parties' respective Presidents. Five business days after receipt of written notice, if the dispute remains unresolved, the matter is referred to arbitration for final resolution.

## 3.5 CONFIDENTIALITY AND INTELLECTUAL PROPERTY

Unless required by law, each party must maintain in strict confidence the Agreement and all information received from the other party. A party receiving confidential information shall not copy or disclose the information to any third party without the prior written consent of the disclosing party unless specifically stipulated in the Agreement. Confidential information remains the sole and exclusive property of the disclosing party.

**THIS AGREEMENT FOR OPERATIONS SERVICES AND MANAGEMENT SERVICES** effective as of the 18th day of September, 2019

BETWEEN:

Hydro One Networks Inc. ("Hydro One Networks")

- and –

Hydro One Indigenous Partnerships GP Inc. ("GPco")

- and -

Niagara Reinforcement Limited Partnership ("NRLP") by its general partner Hydro One Indigenous Partnerships GP Inc.

WHEREAS:

1) NRLP is the transmitter licensed under the *Ontario Energy Board Act* (the "Act") to own and operate the electric transmission tower line spanning from the Allanburg Transformer Station near Niagara Falls, Ontario to the Middleport Transformer Station near Caledonia, Ontario (the "NR Line"), which line went into commercial service in 2019.

2) GPco is an affiliate of Hydro One Networks within the meaning of the ARC.

3) NRLP wishes to subcontract the operation of the NR Line to Hydro One Networks as further set out herein.

4) GPco wishes to obtain the assistance of Hydro One Networks, from time to time, in connection with certain management functions associated with the transmission business of NRLP.

5) The Parties are entering into this Agreement to define their respective rights and obligations with respect to management and operation of the NR Line.

NOW THEREFORE in consideration of the foregoing and the mutual covenants, agreements, terms and conditions contained herein, the Parties intending to be legally bound hereby agree as follows:

## ARTICLE I: DEFINITIONS

### 1.1 Defined Terms

Capitalized terms which are not otherwise defined herein shall have the meaning given to them in the ARC. The following capitalized terms, wherever used in this Agreement, shall have the following meanings:

"**Act**" means the *Ontario Energy Board Act, 1998*;

"**Agreement**" means this Agreement and all amendments made hereto by written Agreement between the Parties in accordance with the terms of this Agreement;

"**ARC**" means the *Affiliate Relationships Code for Electricity Distributors and Transmitters* issued by the OEB in accordance with the Act, as amended from time to time;

"**Claims**" means all losses, costs, damages, expenses, injuries, liabilities, claims, demands and penalties, including reasonable legal fees, experts' fees and court costs, whether incurred through settlement or otherwise, and interest on each of these items, in each case whether arising prior to or after the termination of this Agreement.

"**Connection Agreement**" means the connection agreement which NRLP has or will have entered into with Hydro One Networks governing the interconnection of the NR Line with the transmission systems owned and operated by Hydro One Networks;

"**Fees**" means the Operations Fees and the Management Fees;

"**Force Majeure Event**" means, in relation to a Person, any event or circumstance, or combination of events or circumstances,

(i) that is beyond the reasonable control of the Person;

(ii) that adversely affects the performance by the Person of its obligations under this Agreement; and

(iii) the adverse effects of which could not have been reasonably foreseen or prevented, overcome, remedied or mitigated in whole or in part by the Person through the exercise of diligence and reasonable care and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or acts of terrorism, strikes, lockouts, restrictive work practices or other labour disturbances, unlawful arrests or restraints by government or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the Person of a permit, licence or other authorization or of any applicable law, and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems; provided however, for greater certainty, that the lack, insufficiency or non-availability of funds shall not constitute a Force Majeure Event;

"**Good Utility Practice**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

"**IESO**" means the Independent Electricity System Operator established under the *Electricity Act, 1998*, or its successor;

"**IESO-NRLP Operating Agreement**" means the operating agreement which NRLP has or will enter with the IESO through which the IESO ensures that the NR Line will be operated in a manner which does not compromise the operation or reliability of the IESO-controlled grid to which the NR Line is connected;

"**Management Activities**" means the activities to be undertaken by GPco in connection with the management of transmission business of NRLP which include:

(i) obtaining (including preparation of applications therefor and submission thereof) licences, permits, approvals and rates required in connection with the NR Line, the transmission of electricity thereby and the operation, maintenance, repair and replacement thereof;

(ii) obtaining (including preparation of applications therefor and submission thereof) licences, permits, approvals and rates required in connection with the NR Line and the transmission of electricity thereby;

(iii) representation of NRLP before the OEB;

(iv) the making or filing of declarations, filings and registrations with, or notices to, governmental authorities;

(v) filing and managing warranty claims;

(vi) procuring and maintaining the necessary inventory of replacement parts;

(vii) maintaining records for NRLP;

(viii) defending any litigation commenced against NRLP; and

(ix) such other management activites associated with running the transmission business of NRLP.

"**Management Fees**" means the fees for the Management Services, calculated and adjusted in accordance with this Agreement;

"**Management Services**" means services to be provided by Hydro One Networks to GPco to assist GPco with the performance of the Management Activities, which services will be requested in writing by GPco from time to time;

"**NRLP Transmission Licence**" means the licence or licences issued to NRLP by the OEB pursuant to the Act and in effect from time to time;

"**OEB**" means the Ontario Energy Board established pursuant to the Act;

"**Operations Fees**" means the fees for the Operations Services, calculated and adjusted in accordance with this Agreement;

"**Operations Services**" means all services required in order to operate the NR Line, including without limitation, all operating, maintenance, repair and refurbishment matters and including, without limiting the generality of the foregoing, all services in relation to the monitoring and control of the transmission of electricity across the NR Line in accordance with the NRLP Transmission Licence and all services required to fulfill all of NRLP's obligations under the Connection Agreement and the IESO-NRLP Operating Agreement;

"**Person**" means any natural person, sole proprietorship, partnership, corporation, trust, joint venture, governmental authority, incorporated or unincorporated entity, or incorporated or unincorporated association of any nature; and

"**Taxes**" means any and all applicable federal, state, provincial, or municipal taxes and duties including, but not limited to, sales, use, excise, value added, gross receipts, privilege or other non-recoverable taxes that are mandated or imposed on (i) Hydro One Networks by any jurisdiction or governmental entity in relation to the Operations Services and Management Services (other than taxes that are imposed upon the income, property, payroll or capital of Hydro One Networks), (ii) NRLP (other than taxes that are imposed upon the income, property, payroll or capital of NRLP or any of the partners of NRLP) , or GPco (other than taxes that are imposed upon the income, property, payroll or capital of GPco).

## ARTICLE II: PROVISION OF OPERATIONS AND MANAGEMENT SERVICES

**2.1** Hydro One Networks shall be the exclusive supplier of Operations Services to NRLP commencing on the effective date of this Agreement, provided that NRLP may perform any Operations Services or engage another supplier to perform such services if Hydro One Networks is in default in performing its material obligations hereunder or is unable to perform its material obligations hereunder by reason of a Force Majeure Event, to the extent such services are required to ensure the continued operation of the NR Line.

**2.2** GPco shall be responsible for all Management Activities related to the transmission business of NRLP. GPco may make a request in writing, from time to time, to Hydro One Networks, for Management Services to assist GPco in connection with the Management Activities. Hydro One Networks agrees to provide to GPco those Management Services requested in writing by GPco.

**2.3** Hydro One Networks shall at all times provide Operations Services and Management Services in accordance with Good Utility Practice, the NRLP Transmission Licence, the ARC, all other applicable codes, rules, orders and decisions of the OEB which are binding upon the NR Line, all applicable law, and provided they are not inconsistent with any of the foregoing, Hydro One Networks' own policies and procedures (which may include government directives), and shall do so in the same manner and to the same extent as it provides similar services in connection with its wholly-owned regulated transmission business. Hydro One Networks shall comply with all applicable laws in providing the Operations Services and Management Services.

**2.4** To the extent that Hydro One Networks also provides services similar to the Operations Services or Management Services in respect of its own assets or business, Hydro One Networks will provide such Operations Services and Management Services in a non-discriminatory manner as if it were providing such services to itself or receiving a similar service in relation to its own transmission assets or business. The Fees for such Operations Services and Management Services shall be consistent with the costs incurred by Hydro One Networks for such similar services in relation to Hydro One Networks' transmission assets or business activities which are substantially similar to the NR Line and business activities of NRLP.

**2.5** Upon expiration of this Agreement or termination of this Agreement for reasons other than the default of NRLP, and provided that NRLP is not in default of paying the Fees owing hereunder, Hydro One Networks shall provide, at the request of NRLP, reasonable transition support services to facilitate transition to another operating and management services entity, reimbursable on the basis of the "fully allocated cost" (as defined in the ARC), and otherwise on the terms hereof, for a period of six months following the expiration or effective date of termination of this Agreement, or such shorter period as NRLP may request.

**2.6** Hydro One Networks shall obtain and maintain in force throughout the term of this Agreement, insurance coverage that a reasonable and prudent Person operating a transmission business of a comparable size and scale of Hydro One Networks would carry as part of its business. Hydro One Network's liability insurance shall name NRLP as an additional insured and include a cross-liability and severability of interest clause and a waiver of subrogation clause by the insurer against NRLP. In addition, such liability insurance policy shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by NRLP except in the circumstance where pursuant to Section 2.8, Hydro One Networks chooses to add NRLP as an additional named insured under Hydro One Networks' insurance program.

**2.7** Subject to the provisions of Section 2.8, NRLP shall obtain and maintain in force throughout the term of this Agreement, insurance coverage that a reasonable and prudent transmitter would carry as part of its transmissions business, including, without limitation, property insurance and commercial general liability insurance. Such liability insurance shall name Hydro One Networks as an additional insured, include a cross-liability and severability of interest clause and a waiver of subrogation clause by the insurer against Hydro One Networks. In addition, the insurance policies shall specify that they are primary coverage and not contributory with or in excess of any other insurance that may be maintained by Hydro One Networks. Hydro One Networks will procure such coverage for NRLP as part of the Operations Services.

**2.8** Notwithstanding the foregoing and in the alternative, in consultation with NRLP, Hydro One Networks may choose to add NRLP as an additional named insured under Hydro One Networks' insurance program and allocate to NRLP as Fees, a portion of the premium therefor and any incremental costs borne by Hydro One Networks in accommodating the unique circumstances of NRLP (e.g. reducing deductibles to such reasonable levels requested by NRLP), provided that the amount of the insurance premium allocated to NRLP as Fees (including any incremental costs) shall not exceed the cost of insurance described in Section 2.7 if it were to be obtained as stand-alone insurance coverage.

## ARTICLE III: FEES

**3.1** NRLP shall pay, without duplication, the Operations Fees and all applicable Taxes to Hydro One Networks for the performance of the Operations Services.

**3.2** GPco shall pay, without duplication, the Management Fees and all applicable Taxes to Hydro One Networks for the performance of the Management Services.

**3.3** The Fees for Operations Services and Management Services shall be those costs reasonably incurred by Hydro One Networks in connection with the provision of Operations Services and Management Services in the manner and to the extent provided for hereunder and which are allocated to NRLP and GPco in a manner consistent with the ARC.

**3.4** Fees may be set with reference to actual or estimated consumption and may be charged on a flat fee or per unit basis. Hydro One Networks, acting reasonably and in consultation with NRLP or GPco, as applicable, may elect the most convenient bases for setting Fees. Provided that the approach is acceptable to the OEB, Hydro One Networks may allocate a portion of its transmission business-related costs to NRLP, including a portion of certain types of "direct costs" (as defined in the ARC). Hydro One Networks shall, from time to time as required to keep the information current, and in any event, no less frequently than annually, provide NRLP with a breakdown of Hydro One Network's fully allocated costs of providing the Operations Services.

**3.5** GPco shall use commercially reasonable efforts to recover the Fees payable hereunder by NRLP and GPco in the NRLP transmission rate revenue requirement submissions to the OEB and representations to be made to the OEB in connection therewith.

## ARTICLE IV: INVOICING AND PAYMENT

**4.1** All amounts payable by NRLP and GPco to Hydro One Networks under this Agreement shall be paid in accordance with the invoices rendered by Hydro One Networks to be issued on a periodic basis matching the time period for which NRLP receives payments for the transmission of electricity. NRLP and GPco shall pay Hydro One Networks' invoices within 30 days of receipt thereof.

## ARTICLE V: BUDGETS, ACCOUNTS AND RIGHT TO AUDIT

**5.1** Hydro One Networks shall, for each fiscal year of the term hereof, including any extension of the Initial Term (as defined below) (other than the first year of the Initial Term), provide GPco with a proposed annual operating, maintenance and capital improvement budget for the subsequent fiscal year of NRLP (the "**Budget**") at least sixty (60) days prior to the commencement of the next fiscal year. Such annual Budget shall be accompanied by an annual operating plan prepared by Hydro One Networks setting forth the underlying assumptions and plans in connection with the Budget, and setting forth a brief description of any major system repairs anticipated to be required in such fiscal year. GPco shall notify Hydro One Networks as soon as reasonably practicable, but no later than thirty (30) days after receipt of the Budget, of any questions, comments, objections or suggested modifications which it may have with respect to such proposed Budget, and the parties shall cooperate with each other in developing a mutually acceptable Budget within thirty (30) days thereof. If GPco fails to raise any questions, comments, objections or suggested modifications to the proposed Budget within thirty (30) days after receipt of the proposed Budget, the proposed Budget shall be deemed to have been approved. The parties acknowledge that they have agreed to an annual Budget for the first fiscal year (or part thereof) of the Initial Term of this Agreement.

**5.2** Each Budget will represent Hydro One Networks' estimate of all fully allocated costs for providing the Operations Services under this Agreement during the period to which the Budget relates, and its estimate of all capital improvements required for providing the Operations Services, during the period to which the Budget relates.

**5.3** The parties agree that the Budget may be amended from time to time by mutual agreement to reflect revisions necessitated by unanticipated circumstances including, but not limited to, changes in applicable law, additions or deletions to the scope of the Operations Services hereunder, emergencies and Force Majeure events, provided that Hydro One Networks shall not be required to amend the Budget more frequently than would be required under its normal business and operations practices.

**5.4** The Budget shall reflect anticipated costs of Operations Services by Hydro One Networks on a monthly or quarterly basis and shall be organized by categories mutually agreed upon by the parties. If Hydro One Networks becomes aware that the costs of Operations Services for the current fiscal year may exceed the Budget by 5% or more of the total amount of the Budget, Hydro One Networks shall promptly notify GPco of such anticipated budget overrun and provide GPco a proposed amendment to the Budget. GPco shall notify Hydro One Networks as soon as reasonably practicable, but no later than thirty (30) days after receipt of Hydro One Networks' proposed Budget amendment of any questions, comments, objections or suggested modifications thereto and the parties shall cooperate with each other in developing a mutually acceptable amendment to the Budget. If GPco fails to raise any questions, comments, objections or suggested modifications to the proposed Budget amendment within the specified period, Hydro One Networks' proposed amendment shall be deemed to have been approved. Hydro One Networks shall not, without the written approval of GPco amending the Budget or otherwise authorizing such expenditure, perform any further services or incur any further costs that would result in or increase such Budget overrun, except in the case of an emergency as provided in Section 5.7.

**5.5** If by the start of any fiscal year the parties are unable to reach agreement concerning the Budget for such year, then, until such time as agreement is reached, the Budget for such year shall be based on the corresponding portions of the Budget for the preceding fiscal year, adjusted as follows: (i) with respect to items of expense that do not involve capital additions or improvements, to reflect the net change, if any, between the most recently published Ontario Consumer Price Index, published by Statistics Canada, not seasonally adjusted and the corresponding index in effect twelve months prior, and (ii) with respect to items of expense involving capital additions or improvements, to reflect the net change, if any, between the most recently published Producer Price Index for Capital Equipment, not seasonally adjusted, and the corresponding index in effect twelve months prior.

**5.6** In the event that Hydro One Networks determines that a capital improvement, addition, alteration, repair or replacement not included in the Budget that has an impact of more than 5% of the total amount of the Budget should be made to the NR Line in order to operate the NR Line safely or comply with any laws, regulations or orders of any governmental authority, including laws, regulations or orders relating to environmental compliance or employee safety, Hydro One Networks shall provide GPco with a written notice describing the nature of and reason for the improvement, addition, alteration, repair or replacement. Hydro One Networks shall not make any such improvement, addition, alteration, repair or replacement without GPco's prior consent, which consent shall not be unreasonably withheld or delayed. In the event that GPco refuses to approve of any such Hydro One Networks recommended improvement, addition, alteration, repair or replacement, Hydro One Networks shall have the option to terminate this Agreement in accordance with Section 9.3

**5.7** In the event of an accident or emergency relating to the NR Line, Hydro One Networks may, without obtaining any approvals of GPco which might otherwise be required hereunder, take any action, including, but not limited to, committing or expending funds, deemed by Hydro One Networks to be reasonably necessary under the circumstances. As promptly as reasonably practicable after Hydro One Networks establishes control over such accident or emergency, Hydro One Networks shall furnish to GPco a reasonably detailed written description of the accident or emergency and the manner in which such accident or emergency was handled by Hydro One Networks. Hydro One Networks shall be entitled to compensation for costs incurred pursuant to this Section 5.7 in addition to all other compensation provided for under this Agreement.

**5.8** Except as provided by Section 5.7 in the case of an emergency, Hydro One Networks shall perform all services hereunder in accordance with the annual operating plan accompanying the Budget.

**5.9** The parties hereby agree to keep all necessary and proper accounts and records relating to the subject matter hereof. Such accounts and records, including invoices, receipts, time cards and vouchers shall at all reasonable times be open to audit, inspection and copying by each Party to this Agreement. Accounts and records shall be preserved and kept available for audit for a period of six years.

## <u>ARTICLE VI: LIMITATION OF LIABILITY AND FORCE MAJEURE EVENTS</u>

**6.1** Other than for sums payable under this Agreement, Hydro One Networks shall only be liable to NRLP and GPco and NRLP and GPco shall only be liable to Hydro One Networks for any damages that arise directly out of its gross negligence or willful misconduct in meeting its respective obligations under this Agreement. Notwithstanding the generality of the foregoing, neither party shall be liable to the other party under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

**6.2** In any event, except with respect to gross negligence or willful misconduct, the total liability of Hydro One Networks to NRLP and GPco and the total liability of NRLP and GPco to Hydro One Networks in connection with this Agreement whether it arises by statute, contract, tort or otherwise, will not exceed the value of the total amounts payable by NRLP and GPco to Hydro One Networks for the Operations Services and Management Services in the year that such liability is incurred.

**6.3** No party shall be liable to the other for any loss, damage or delay, or inability to perform any obligation under this Agreement in whole or in part due to a Force Majeure Event.

**6.4** NRLP will indemnify and save harmless Hydro One Networks providing Operations Services from and against any and all Claims that Hydro One Networks may suffer, sustain or incur in connection with the provision of the Operations Services except to the extent caused or arising from the gross negligence or wilful misconduct of Hydro One Networks.

**6.5** If a Force Majeure Event prevents a party from performing any of its obligations under this Agreement, such party shall (1) expeditiously, and without delay, notify the other party of the Force Majeure Event and its good faith assessment of the effect that the Force Majeure Event will have on its ability to perform any of its obligations, which notice shall be confirmed in writing as soon as reasonably practicable if such immediate notice is not in writing; (2) not be entitled to suspend performance of any of its obligations under the Agreement to any greater extent or for any longer duration than is caused by the Force Majeure Event; (3) use commercially reasonable efforts to mitigate the effects of such Force Majeure Event and to resume full performance of its obligations hereunder; (4) keep the other party informed of such efforts on a continuing basis; and (5) provide written notice to the other party of the resumption of the performance of any obligations affected by the Force Majeure Event.

**6.6** Notwithstanding any of the foregoing, settlement of any strike, lockout, or labour dispute constituting a Force Majeure Event shall be within the sole discretion of the party to the Agreement involved in such strike, lockout, or labour dispute and the requirement that a party must use commercially reasonable efforts to mitigate the effects of a Force Majeure Event and resume full performance hereunder shall not apply to strikes, lockouts, or labour disputes.

## ARTICLE VII: DISPUTE RESOLUTION PROCEDURES

**7.1** Any controversy, dispute, difference, question or claim (collectively "Dispute"), arising between the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a conference of senior officers of Hydro One Networks and GPco shall be settled in accordance with this section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought. The Presidents from each party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then a Party may refer the Dispute to adjudication in court or, if all Parties agree, to arbitration before a single arbitrator. Insofar as they do not conflict with this Section 7.1, the Rules for Procedure for Commercial Arbitration of the Arbitration and Mediation Institute of Canada Inc./International Chamber of Commerce Rules of Arbitration in effect at the date of commencement of any arbitration held under this Agreement will apply to the arbitration. A Party may enter any judgment upon any award rendered by the arbitrator in any court having jurisdiction. The arbitration will be conducted in English under the *Arbitration Act, 1991* (Ontario) and will take place in either the City of Toronto or such other place as the Parties may agree and at such time and place as the arbitrator may fix. Notwithstanding the foregoing, if the subject matter of any Dispute is also the subject matter of a Dispute under Article 13 of the Limited Partnership Agreement governing NRLP, the resolution of the Dispute under the Article 13 of the Limited Partnership Agreement governing NRLP shall govern and be applicable to the resolution of the Dispute under this Agreement and such matter shall not be subject to further arbitration or adjudication under this Agreement.

## ARTICLE VIII: CONFIDENTIALITY AND INTELLECTUAL PROPERTY

**8.1** Each party (the "Receiving Party") shall maintain in strict confidence this Agreement and the existence and contents thereof and all confidential or proprietary information of the other party, (the "Disclosing Party") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal, financial or professional advisors (the "Disclosing Party Representatives") (collectively the "Confidential Information"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its partners, shareholder, directors, officers, employees, consultants, agents, professional advisors or lenders (the "Receiving Party Representatives") having a need to know same and who have undertaken a like obligation to maintain its confidentiality. For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Freedom of Information and Protection of Privacy Act* (Ontario) and the *Personal Information Protection and Electronic Documents Act* (Canada), as they may be amended) and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement.

**8.2** The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule “A” attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Article VIII and all applicable statutes, regulations, by-laws, standards and codes, as amended.

**8.3** The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party’s Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

**8.4** The foregoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

(i) is previously known to or lawfully in the possession of the Receiving Party prior to the date of disclosure as evidenced by the Receiving Party’s written record;

(ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;

(iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;

(iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by, the Receiving Party or the Receiving Party Representatives; or

(v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process, including, without limitation, an order of or legal process involving a regulatory authority such as the Ontario Energy Board.

**8.5** The parties acknowledge and agree that the Confidential Information (other than Confidential Information contained in this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the Confidential Information it has disclosed to the Receiving Party.

**8.6** The Receiving Party agrees that it shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

**8.7** All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request except that any information, plans, layouts, specifications, descriptions or other information necessary to the continued operation and maintenance of the NR Line and its parts and components, or to the replacement of any such parts or components, need not be returned and may be used or applied in the continued operation and maintenance of the NR Line.

## ARTICLE IX: TERM AND TERMINATION

**9.1** This Agreement shall continue in full force and effect for an initial term of five years (the “Initial Term”) and unless terminated in accordance with Section 9.2, shall thereafter be automatically renewed for successive periods of five years upon the same terms and conditions.

**9.2** Either party may terminate this Agreement, effective at the end of the then current five-year term, on at least twelve months’ prior written notice.

**9.3** Hydro One Networks may terminate this Agreement on 60 days prior written notice in the event that NRLP refuses to approve a capital improvement, addition, alteration, repair or replacement recommended by Hydro One Networks in accordance with Section 5.6.

**9.4** In the event of termination or expiration of this Agreement: (i) Hydro One Networks shall deliver to GPco all books, records and accounts which it has developed and maintained relating solely to the NR Line or its operations or the business of NRLP and return all property owned by NRLP, and (ii) the Parties shall take all steps as may be reasonably required to complete any final accounting between them or to provide for the completion of matters contemplated hereunder.

## ARTICLE X: GENERAL

**10.1** This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

**10.2** The rights and obligations of the parties under this Agreement shall at all times be subject to all applicable laws, regulations, orders and directives of any authority of competent jurisdiction, including the OEB, and shall be deemed to be amended to the extent required to comply with same.

**10.3** This Agreement constitutes the entire Agreement between the parties with respect to the Operations Services and Management Services and supersedes all prior oral or written representations and Agreements concerning the subject matter of this Agreement.

**10.4** This Agreement shall extend to, be binding upon and enure to the benefit of the permitted assigns and the respective successors of NRLP, GPco and Hydro One Networks.

**10.5** Neither this Agreement nor any provision hereof is intended to confer upon any Person other than the parties hereto any rights or remedies hereunder.

**10.6** If any party determines that in its reasonable discretion that any further instruments or other actions seem necessary or desirable to carry out the terms of this Agreement, the other parties shall execute and deliver all such instruments and do all such actions as such parties agree in their reasonable discretion as necessary or desirable to carry out the terms of this Agreement.

**10.7** No delay or failure in exercising any right under this Agreement or any partial or single exercise of any right, will constitute a waiver of that right or any other rights under this Agreement. No consent to a breach of any express or implied term set out in this Agreement constitutes consent to any subsequent breach.

**10.8** If any term, covenant or condition of this Agreement or the application or effect of any such term, covenant or condition is held to be invalid as to any Person, entity or circumstance or is determined to be not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant or condition shall remain in effect to the maximum extent permitted by law and, all other terms, covenants and conditions of this Agreement and their application shall not be affected, but shall remain in full force and effect and the parties shall be relieved of their respective obligations under this Agreement only to the extent necessary to comply with the court or government agency holding.

**10.9** This Agreement does not and shall not be construed to create or establish a partnership, agency, joint venture, lease, licence or any other relationship between the parties hereto, nor constitute either party as an agent of the other. Neither party hereto shall hold itself out to others by act or omission, contrary to the terms of this Agreement.

**10.10** This Agreement and the rights and obligations hereunder may not be assigned in whole or in part by Hydro One Networks except with the prior written consent of NRLP, in its sole discretion. This Agreement and the rights and obligations hereunder may not be assigned in whole or in part by NRLP other than (i) to the transferee of the NR Line approved by the OEB, or (ii) with the prior written consent of Hydro One Networks, in its sole discretion.

**10.11** This Agreement and any amendment, supplement, restatement or termination of this Agreement in whole or in part may be executed and delivered in counterparts by means of portable document format (PDF), electronic signature or other transmission method, each of which when so executed and delivered shall be an original, but all such counterparts shall together constitute one and the same instrument.

***[Remainder of page intentionally left blank]***

**IN WITNESS WHEREOF,** the parties hereto have caused this Agreement to be executed by the signatures of their proper officers duly authorized in that behalf as of this ____ day of __________________________.

**HYDRO ONE NETWORKS INC.**

By: ___________________________________

Name: Chris Lopez
Title: Chief Financial Officer

I have the authority to bind the Corporation.

**NIAGARA REINFORCEMENT LIMITED PARTNERSHIP, by its general partner HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.**

By: ______________________________________

Name: Chris Lopez
Title: President

I have the authority to bind the Corporation.

**HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.**

By: ______________________________

Name: Chris Lopez
Title: President

I have the authority to bind the Corporation.

## **Schedule "A"**

Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

*The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.*

1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.

2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.

3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.

4) The Receiving Party shall ensure that methods of protection will include:

(a) physical measures, for example, locked filing cabinets and restricted access to offices;

(b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;

(c) technological measures, for example, the use of passwords and encryption; and

(d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

# COMMON CORPORATE COSTS, COST ALLOCATION METHODOLOGY

Allocation of Common Corporate Costs to Hydro One affiliates, and to NRLP, is based on an established cost allocation approach supported by cost causality principles.

The Common Corporate Costs OM&A programs include the support of Corporate Common Functions and Services ("CCF&S"), Asset Management, Information Technology, and Operating Programs.

Specifically related to NRLP, the allocated CCF&S costs are for services provided by Finance, Taxation, Planning, Security Operations, Real Estate Services, Indigenous Relations, Regulatory Affairs and General Counsel.

Since 2004, in connection with each major cost of service application, Hydro One has commissioned a study by Black and Veatch to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

The allocation of Common Corporate Costs to NRLP for the test years (2020 to 2024) is forecast to be $0.20 million annually. This amount was calculated using the same methodology as that for B2M LP. The resulting amount was about 10% less for NRLP. This is reflective of the fact that there is expected to be less effort around Treasury and Real Estate functions but otherwise, the cost of corporate services is essentially the same between the 2 entities.

# DEPRECIATION EXPENSES

## 1. INTRODUCTION

The purpose of this evidence is to summarize the method and amount of NRLP's depreciation and amortization expense for the 2020 to 2024 test years.

The depreciation and amortization expense for HONI's submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June 2006. HONI submitted a number of Foster studies in subsequent rate applications (including EB-2014-0140 and EB-2016-0160) and completed a Depreciation Study for B2M LP on September 27, 2013 (EB-2015-0026). The Board accepted the costs flowing from the Depreciation Study in that case for the purpose of determining B2M LP's depreciation rates and expenses for 2015 to 2019.

Foster completed a new depreciation study in 2017 for HONI Transmission in support of its 2020 to 2022 application (EB-2019-0082). This study forms the basis of NRLP's depreciation rates and expenses in this Application. The assets are the same and are expected to perform the same as the assets on which HONI's study was based. There is no additional value or need to incur the significant additional expense to maintain unique NRLP depreciation rates.

## 2. DEPRECIATION EXPENSE

NRLP relied upon HONI's new depreciation study for transmission assets completed in 2017, which used the Foster methodology to determine the depreciation rates proposed to be used in the calculation of depreciation expenses for 2020. A detailed depreciation schedule is included in Table 1.

# Table 1 – NRLP Depreciation and Amortization Expenses ($ Million)

Year Ending December 31
($ Millions)

| Line No. | Particulars | 2019 Deprn Rate | 2019 Provision ($M) | 2020 Deprn Rate | 2020 Provision ($M) | 2021 Deprn Rate | 2021 Provision ($M) | 2022 Deprn Rate | 2022 Provision ($M) | 2023 Deprn Rate | 2023 Provision ($M) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (a) | (b) | (a) | (b) | (a) | (b) | (a) | (b) |
| | Depreciation Expenses | | | | | | | | | | |
| 1 | Major Fixed Assets | | | | | | | | | | |
| 2 | Land | 0.00% | 0.00 | 0.00% | 0.00 | 0.00% | 0.00 | 0.00% | 0.00 | 0.00% | 0.00 |
| 3 | Land-Rights | 0.96% | 0.00 | 0.96% | 0.01 | 0.96% | 0.01 | 0.96% | 0.01 | 0.96% | 0.01 |
| 4 | Towers and Fixtures | 1.28% | 0.50 | 1.28% | 1.00 | 1.28% | 1.00 | 1.28% | 1.00 | 1.28% | 1.00 |
| 5 | Overhead Lines | 1.44% | 0.29 | 1.44% | 0.58 | 1.44% | 0.58 | 1.44% | 0.58 | 1.44% | 0.58 |
| 6 | | | | | | | | | | | |
| 7 | | | | | | | | | | | |
| 8 | Depreciation on Fixed Assets | **1.34%** | 0.79 | **1.34%** | 1.59 | **1.34%** | 1.59 | **1.34%** | 1.59 | 1.34% | 1.59 |
| 9 | Less Capitalized Depreciation | | - | | - | | - | | - | | - |
| 10 | Asset Removal Costs | | - | | - | | - | | - | | - |
| 11 | Total Depreciation Expenses | | 0.79 | | 1.59 | | 1.59 | | 1.59 | | 1.59 |
| | Amortization Expenses | | | | | | | | | | |
| 12 | Other Amortization | | - | | - | | - | | - | | - |
| 13 | Total Amortization Expenses | | - | | - | | - | | - | | - |
| 14 | Total Depreciation & Amortization Expenses | | 0.79 | | 1.59 | | 1.59 | | 1.59 | | 1.59 |
| 15 | Depreciation & Amortization for recovery | | 0.79 | | 1.59 | | 1.59 | | 1.59 | | 1.59 |

# CORPORATE INCOME TAXES

## 1. OVERVIEW

This Exhibit explains how NRLP calculates its income tax expenses for the purposes of rate recovery. Exhibit F, Tab 6, Schedule 1, Attachments 1 and 2 contain detailed calculations of income tax for the Bridge and Test year, including supporting schedules and reconciliations. Exhibit F, Tab 7, Schedule 1, Attachment 1 includes a copy of the partnership's NIL tax return for its first fiscal period from September 19, 2018, its formation date to December 31, 2018. The information provided in this Application is consistent with Section 2.8.11 of the Filing Requirements.

Over the Test period, NRLP is expected to incur general income tax expenses in the form of Ontario corporate minimum tax ("OCMT") as the allowable capital cost allowance ("CCA") deduction is expected to exceed the taxable income.

# 2. OVERVIEW OF INCOME TAXES

## 2.1 INTRODUCTION

NRLP is a limited partnership formed under the *Limited Partnerships Act* (Ontario). A partnership is generally not taxable under the *Income Tax Act*. A partnership is required to compute its taxable income, which is then allocated to its partners who are responsible for reporting income and payment of taxes thereon. The partners of NRLP are:

| Partners | Description |
|---|---|
| Hydro One Networks Inc. | A corporation owned indirectly by Hydro One Inc. |
| Hydro One Indigenous Partnerships GP Inc. (“HOIP”) | A corporation owned indirectly by Hydro One Inc. and the General Partner of NRLP |
| Mississaugas of the Credit First Nation Toronto Purchase Trust (“MCFN”) | A trust owned directly by a First Nation |
| 11100726 Canada Limited (“SNGR”) | A corporation owned directly by a First Nation |

MCFN and SNGR, its beneficiaries or shareholders are not subject to payment in lieu of corporate tax (“PILS”) or Corporate Income Tax. Therefore, the taxable income in NRLP allocated to First Nations will not be subject to income tax. This ultimately leads to less total income tax paid, which is a saving for ratepayers.

## 2.2 REGULATORY INCOME TAX EXPENSE

Regulatory Income Taxes for NRLP are determined by applying the statutory tax rate to the portion of regulatory taxable income allocated to Hydro One Networks Inc. and Hydro One Indigenous Partnerships GP Inc., the taxable corporate partners of NRLP.

### 2.2.1 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the 2020 Test Year, as set out in Table 1, comprising a federal rate of 15% and a provincial rate of 11.5%.

**Table 1 - Combined Income Tax Rates**

| | Bridge | Test | | | | |
|---|---|---|---|---|---|---|
| | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** |
| Federal Tax Rate (%) | 15.00 | 15.00 | 15.00 | 15.00 | 15.00 | 15.00 |
| Provincial Rate (%) | 11.50 | 11.50 | 11.50 | 11.50 | 11.50 | 11.50 |
| Total Statutory Tax Rate (%) | **26.50** | **26.50** | **26.50** | **26.50** | **26.50** | **26.50** |

NRLP proposes that any variance between actual taxes payable and forecast taxes resulting from changes in tax policy, legislation changes or rate changes for income tax or capital cost allowance be captured in a deferral account as per Section 7.1 of the Electricity Distribution Rate ("EDR") Handbook. NRLP has included its request for such an account in Exhibit H, Tab 1, Schedule 1.

### 2.2.2 ONTARIO CORPORATE MINIMUM TAX

Ontario corporate minimum tax ("OCMT") is designed to impose a minimum tax based on financial statement income calculated without most tax adjustments. The OCMT paid in the year can be applied to reduce taxes payable in a future year(s)[1]. Hydro One Networks Inc. and Hydro One Indigenous Partnerships GP Inc. be subject to OCMT in the Bridge year 2019 and Test year 2020 as shown in Exhibit F, Tab 6, Schedule 1, Attachment 1. NRLP will use OCMT expense incurred in the Bridge and Test years to reduce income tax expenses in the future years when there is a sufficient level of taxable income. Net Income for tax purposes is expected to be less than zero in all years throughout the Bridge and Test period and OCMT will, therefore, be applicable. These credits are expected to be accumulated and depleted in the future to reduce future income taxes payable.

[11] OCMT has a 20-year carry forward period and it will expire unutilized after 20 year period.

## 3. RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax ("NIBT") and taxable income for the 2020 Test year is provided in Exhibit F, Tab 6, Schedule 1, Attachment 1. This schedule contains the income tax computation and also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance ("CCA"). The calculation of CCA is provided in Exhibit F, Tab 6, Schedule 1, Attachment 2.

CCA is calculated on a declining balance and, as a result, the amount of CCA available to reduce taxable income decreases. Under the Accelerated Investments Incentive program included in the Bill C-97, *the Budget Implementation Act, 2019, No. 1*, it provides for a first-year increase of CCA deductions for eligible capital assets acquired after November 20, 2018, and placed into service prior to January 1, 2028 (Accelerated CCA). Although the NRLP assets were placed into service in 2019, a large percentage of the assets were completed prior to the November 20, 2018 date. As such, only a small portion of the costs incurred during the period from November 21, 2018, to the in-service date would be eligible for the Accelerated CCA. This has been reflected in the computation of the taxable income for the applicable years.

## 4. OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of NRLP taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared by using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes, such as depreciation. On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT such as CCA.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

## 5. TAXABLE TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized on the utilities' balance sheets for forgone revenue, or for expenses that have been incurred for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board.

For example, as shown in Table 2, assuming that a 26.5% tax rate and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year (in Year 1) in which the expense has been incurred. If the OEB subsequently approves recovery of this expense over a two-year period through a rate rider (in Years 2 and 3), the utility will include the approved recoverable amounts in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

**Table 2 - Example of the Income Tax Treatment of Deferral Account Disposition**

| | Year 1 | Year 2 | Year 3 | NET |
|---|---|---|---|---|
| **Income (deduction)** | (100) | 50 | 50 | Nil |
| **Tax Refund (payable)** | 26.5 | (13.25) | (13.25) | Nil |
| **Cash Inflow (outflow)** | (73.5) | 36.75 | 36.75 | Nil |

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with Section 2.8.11 of the Filing Requirements issued February 11, 2016, which states:

> *"Regulatory assets (and regulatory liabilities) must generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts."*

## 6. INTEGRITY CHECKS

NRLP has performed the integrity checks set described in Section 2.8.11.2 of the Filing Requirements. Please note there are no Historical years as 2019 is the first year whereby NRLP is awarded the electricity transmission license[2] and consequently seeking approval from OEB for revenue requirements and rates subsequent to the approval for Hydro One Networks Inc. to transfer transmission assets to NRLP in 2019[3].

## 7. SUPPORTING ATTACHMENTS

The attachments supporting the determination of the income tax expense are provided in the following attachments:

**Attachment 1:** Calculation of Utility Income Taxes – Bridge and Test Year

**Attachment 2:** Calculation of Capital Cost Allowance – Bridge and Test Year

[2] ET-2018-0277 issued September 12, 2019
[3] EB 2018-0275

NRLP
Calculation of Utility Income Taxes
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

| SUMMARY OF TAX EXPENSE | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Hydro One Networks Inc. | 0.03 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| Hydro One Indigenous Partnerships GP Inc | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 11100726 Canada Limited (Six Nations) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Mississaugas of the New Credit First Nation Toronto Purchase Trust | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total** | **0.03** | **0.06** | **0.06** | **0.06** | **0.06** | **0.06** |

**NRLP**

| Line No. | Particulars | 2019 (a) | 2020 (b) | 2021 (c) | 2022 (d ) | 2023 (e) | 2024 (f) |
|---|---|---|---|---|---|---|---|
| | Determination of Taxable Income/(Loss) | | | | | | |
| 1 | Regulatory Net Income/(Loss) (before tax) | 2.16 | 4.30 | 4.24 | 4.18 | 4.12 | 4.07 |
| 2 | Book to Tax Adjustments: | | | | | | |
| 3 | Depreciation and amortization | 0.79 | 1.59 | 1.59 | 1.59 | 1.59 | 1.59 |
| 4 | Capital Cost Allowance | (5.28) | (9.13) | (8.40) | (7.73) | (7.11) | (6.54) |
| 5 | Other | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 6 | Total Adjustments | (4.49) | (7.54) | (6.81) | (6.14) | (5.52) | (4.95) |
| 7 | **Regulatory Taxable Income/(Loss) before Loss Carry Forward** | **$ (2.32)** | **$ (3.24)** | **$ (2.57)** | **$ (1.96)** | **$ (1.40)** | **$ (0.89)** |
| | Allocation of Taxable Income/(Loss) | | | | | | |
| 8 | Hydro One Networks Inc. | (1.26) | (1.75) | (1.38) | (1.05) | (0.74) | (0.46) |
| 9 | Hydro One Indigenous Partnerships GP Inc | (0.00) | (0.00) | (0.00) | (0.00) | (0.00) | (0.00) |
| 10 | 11100726 Canada Limited (Six Nations) | (0.59) | (0.83) | (0.66) | (0.51) | (0.36) | (0.24) |
| 11 | Mississaugas of the New Credit First Nation Toronto Purchase Trust | (0.47) | (0.66) | (0.53) | (0.40) | (0.29) | (0.19) |
| 12 | Total | $ (2.32) | $ (3.24) | $ (2.57) | $ (1.96) | $ (1.40) | $ (0.89) |
| | Tax Rates | | | | | | |
| 13 | Federal Tax | 15.00 % | 15.00 % | 15.00 % | 15.00 % | 15.00 % | 15.00 % |
| 14 | Provincial Tax | 11.50 % | 11.50 % | 11.50 % | 11.50 % | 11.50 % | 11.50 % |
| 15 | Total Tax Rate | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 % |

NRLP
Calculation of Utility Income Taxes
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

**Hydro One Networks Inc.**

| Line No. | Particulars | 2019 (a) | 2020 (a) | 2021 (b) | 2022 (c ) | 2023 (d) | 2024 (e) |
|---|---|---|---|---|---|---|---|
| | Determination of Income Taxes | | | | | | |
| 1 | Allocation of Taxable Income/(Loss) from NRLP | (1.26) | (1.75) | (1.38) | (1.05) | (0.74) | (0.46) |
| 2 | Loss Carryforward | 1.26 | 1.75 | 1.38 | 1.05 | 0.74 | 0.46 |
| 3 | Taxable Income after loss carryforward | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Tax Rate | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 |
| 5 | Sub Total | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 % |
| 6 | Additional Taxes due to Negative ACB | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 7 | **Income Tax Expense** | **$ 0.00** | **$ 0.00** | **0.00** | **0.00** | **0.00** | **0.00** |
| | Loss Continuity Schedule | | | | | | |
| 8 | Opening Losses Carryforward | 0.00 | (1.26) | (3.01) | (4.40) | (5.44) | (6.18) |
| 9 | Losses (Incurred)/Utilized during the year | (1.26) | (1.75) | (1.38) | (1.05) | (0.74) | (0.46) |
| 10 | Closing Losses Carryforward | (1.26) | (3.01) | (4.40) | (5.44) | (6.18) | (6.64) |
| | Determination of Corporate Minimum Tax | | | | | | |
| 11 | Allocation of Accounting Income from NR LP | 1.20 | 2.39 | 2.36 | 2.32 | 2.29 | 2.26 |
| 12 | Corporate Minimum Tax Rate | 2.70 % | 2.70 % | 2.70 % | 2.70 % | 2.70 % | 2.70 |
| 13 | Corporate Minimum Tax Potentially Applicable | 0.03 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 % |
| 14 | Ontario Income Tax | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 15 | **Corporate Minimum Tax Payable (Utilized)** | **$ 0.03** | **$ 0.06** | **$ 0.06** | **$ 0.06** | **$ 0.06** | **$ 0.06** |
| 16 | Opening CMT Credit Carryforward | 0.00 | 0.03 | 0.10 | 0.16 | 0.22 | 0.29 |
| 17 | CMT Credit Incurred/(utilized) | 0.03 | 0.06 | 0.06 | 0.06 | 0.06 | 0.06 |
| 18 | Closing CMT Credit Carryforward | 0.03 | 0.10 | 0.16 | 0.22 | 0.29 | 0.35 |
| 19 | **Total Taxes Expense for Hydro One Networks Inc.** | **$ 0.03** | **$ 0.06** | **$ 0.06** | **$ 0.06** | **$ 0.06** | **$ 0.06** |

NRLP
Calculation of Utility Income Taxes
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

**Hydro One Indigenous Partnerships GP Inc**

| Line No. | Particulars | 2019 (a) | 2020 (a) | 2021 (b) | 2022 (c ) | 2023 (d) | 2024 (e) |
|---|---|---|---|---|---|---|---|
| | Determination of Income Taxes | | | | | | |
| 1 | Allocation of Taxable Income/(Loss) from NRLP | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2 | Loss Carryforward | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3 | Taxable Income/(Loss) after loss carryforward | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 4 | Tax Rate | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 % | 26.50 |
| 5 | **Income Tax Expense** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** % |
| | Loss Continuity Schedule | | | | | | |
| 6 | Opening Losses Carryforward | 0.00 | (0.00) | (0.01) | (0.01) | (0.01) | (0.01) |
| 7 | Losses (Incurred)/Utilized during the year | (0.00) | (0.00) | (0.00) | (0.00) | (0.00) | (0.00) |
| 8 | Closing Losses Carryforward | (0.00) | (0.01) | (0.01) | (0.01) | (0.01) | (0.01) |
| | Determination of Corporate Minimum Tax | | | | | | |
| 9 | Allocation of Accounting Income/(Loss) from NRLP | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 10 | Corporate Minimum Tax Rate | 2.70 % | 2.70 % | 2.70 % | 2.70 % | 2.70 % | 2.70 |
| 11 | Corporate Minimum Tax Potentially Applicable | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 % |
| 12 | Ontario Income Tax | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 13 | **Corporate Minimum Tax Payable (Utilized)** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** |
| 14 | Opening CMT Credit Carryforward | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 15 | CMT Credit Incurred/(utilized) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 16 | Closing CMT Credit Carryforward | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 17 | **Total Taxes Expense for Hydro One Indigenous Partnerships GP Inc** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** | $ **0.00** |

NRLP
Calculation of Utility Income Taxes
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

**Six Nations**

| Line No. | Particulars | 2019 (a) | 2020 (a) | 2021 (b) | 2022 (c ) | 2023 (d) | 2024 (e) |
|---|---|---|---|---|---|---|---|
| | Determination of Income Taxes | | | | | | |
| 1 | Allocation of Taxable Income/(Loss) from NRLP | (0.59) | (0.83) | (0.66) | (0.51) | (0.36) | (0.24) |
| 2 | Tax Rate | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % |
| 3 | **Income Tax Expense** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |
| | Determination of Corporate Minimum Tax | | | | | | |
| 4 | Allocation of Accounting Income/(Loss) from NRLP | 0.53 | 1.06 | 1.04 | 1.03 | 1.02 | 1.00 |
| 5 | Corporate Minimum Tax Rate | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % |
| 6 | **Corporate Minimum Tax Payable** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |
| 7 | **Total Tax Expense for Six Nations** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |

**Mississaugas of the New Credit First Nation Toronto Purchase Trust**

| Line No. | Particulars | 2019 (a) | 2020 (a) | 2021 (b) | 2022 (c ) | 2023 (d) | 2024 (e) |
|---|---|---|---|---|---|---|---|
| | Determination of Income Taxes | | | | | | |
| 1 | Allocation of Taxable Income from NRLP | (0.47) | (0.66) | (0.53) | (0.40) | (0.29) | (0.19) |
| 2 | Tax Rate | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % |
| 3 | **Income Tax Expense** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |
| | Determination of Corporate Minimum Tax | | | | | | |
| 4 | Allocation of Accounting Income from NRLP | 0.43 | 0.85 | 0.84 | 0.82 | 0.81 | 0.80 |
| 5 | Corporate Minimum Tax Rate | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % | 0.00 % |
| 6 | **Corporate Minimum Tax Payable** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |
| 7 | **Total Tax Expense for Mississaugas of the New Credit** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** | **$ 0.00** |

NRLP
Calculation of Capital Cost allowance (CCA)
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

2019

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | - | 119.43 | 119.43 | (59.72) | 59.72 | 0.08 | 4.78 | 0.50 | 114.15 |
| UCC | - | 119.43 | 119.43 | (59.72) | 59.72 | 0.24 | 4.78 | 0.50 | 114.15 |
| | | | | | | | **TOTAL CCA** | **5.28** | |

2020

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | 114.15 | - | 114.15 | - | 114.15 | 0.08 | 9.13 | | 105.02 |
| UCC | 114.15 | - | 114.15 | - | 114.15 | 0.24 | 9.13 | | 105.02 |
| | | | | | | | **TOTAL CCA** | **9.13** | |

2021

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | 105.02 | - | 105.02 | - | 105.02 | 0.08 | 8.40 | | 96.62 |
| UCC | 105.02 | - | 105.02 | - | 105.02 | 0.24 | 8.40 | | 96.62 |
| | | | | | | | **TOTAL CCA** | **8.40** | |

NRLP
Calculation of Capital Cost allowance (CCA)
Bridge (2019) and Test Years (2020 to 2024)
Year Ending December 31
($ Millions)

2022

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | 96.62 | - | 96.62 | - | 96.62 | 0.08 | 7.73 | | 88.89 |
| UCC | 96.62 | - | 96.62 | - | 96.62 | 0.24 | 7.73 | | 88.89 |
| | | | | | | | **TOTAL CCA** | **7.73** | |

2023

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | 88.89 | - | 88.89 | - | 88.89 | 0.08 | 7.11 | | 81.78 |
| UCC | 88.89 | - | 88.89 | - | 88.89 | 0.24 | 7.11 | | 81.78 |
| | | | | | | | **TOTAL CCA** | **7.11** | |

2024

| CCA Class | Opening UCC | Net Additions | UCC pre-1/2 yr | 50% net additions | UCC for CCA | CCA Rate | CCA | Accelerated CCA on eligible net additions | Closing UCC |
|---|---|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | 0.04 | - | | - |
| 14.1 (Pre-2017) | - | - | - | - | - | 0.07 | - | | - |
| 14.1 (Post-2017) | - | - | - | - | - | 0.05 | - | | - |
| 47 | 81.78 | - | 81.78 | - | 81.78 | 0.08 | 6.54 | | 75.23 |
| UCC | 81.78 | - | 81.78 | - | 81.78 | 0.24 | 6.54 | | 75.23 |
| | | | | | | | **TOTAL CCA** | **6.54** | |

# INCOME TAX RETURN

Attachment 1: T5013 – Partnership Financial Return

Canada Revenue Agency / Agence du revenu du Canada

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# Partnership Financial Return

**T5013 Financial**

Full disclosure is required on all documents relating to this return. All the information requested in this form and in the documents supporting your information return is "prescribed information".

Complete this financial return using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at canada.ca/my-cra-business-account. Your authorized representative can access this service in Represent a Client at canada.ca/taxes-representatives.

**Note:** All legislative references provided on this form are from the Income Tax Act.

055 **For office use only**

## Identification

**Partnership account number**
001 28099 4377 RZ0001

**Is this an amended return?** 040 [ ] 1 Yes [X] 2 No

**Partnership name:**
006 Niagara Reinforcement Limited Partnership
007

**Fiscal period to which this information return applies:**
060 Fiscal period start (Year Month Day) From 2018-09-19
061 Fiscal period end * (Year Month Day) to 2018-12-31
* If you answer **Yes** to question 078 below, enter the date when the partnership ceased to exist.

**Partnership operating or trading name:**
008 Niagara Reinforcement Limited Partnership
009

062 **The end members of this partnership are** (tick the applicable boxes):
01 [ ] Individuals (including trusts)
02 [X] Corporations

**Location of the partnership head office**
Has this location changed since the last time you filed a partnership information return? 010 [ ] 1 Yes [X] 2 No
If **Yes**, enter the address of the new location on lines 011 to 018:
011
012
City 015 — Province/State 016
Country 017 — Postal or ZIP code 018

**Is this the first year of filing?** 070 [X] 1 Yes [ ] 2 No
If **Yes**, enter the date the partnership was created: 071 (Year Month Day) 2018-09-19

**Number of T5013 slips:** 073 2

**Is this the partnership's final information return up to dissolution?** 078 [ ] 1 Yes [X] 2 No

**Mailing address of the partnership** (if different from the head office address)
Has this address changed since the last time you filed a partnership information return? 020 [ ] 1 Yes [X] 2 No
If **Yes**, enter the new mailing address on lines 021 to 028:
021 c/o
023
024
City 025 — Province/State 026
Country 027 — Postal or ZIP code 028

**If an election was made under section 261 by one or more partners, state the functional currency code used for this return:** 079

**Was the partnership a Canadian partnership throughout the fiscal period?** 082 [X] 1 Yes [ ] 2 No

086 **Type of partnership at the end of the fiscal period**

| **Non tax shelter** | **Tax shelter (TS)** |
|---|---|
| [ ] 01 General partnership | [ ] 11 General partnership |
| [X] 02 Limited partnership | [ ] 12 Limited partnership |
| [ ] 03 Limited liability partnership | [ ] 13 Co-ownership |
| [ ] 08 Investment club | [ ] 19 Other (specify below) |

**Location of the partnership's books and records** (if different from the head office address)
Has this location changed since the last time you filed a partnership information return? 030 [X] 1 Yes [ ] 2 No
If **Yes**, enter the address of the new location on lines 031 to 038:
031 483 Bay Street, 7th floor, South Tower
032
City 035 Toronto — Province/State 036 ON
Country 037 CAN — Postal or ZIP code 038 M5G 2P5

**If the partnership is a tax shelter (TS), enter the TS identification number:** 087

**Industry code (NAICS):** 098 221121

Approval code: RC-18-P006


Canada

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| | |
|---|---|
| **001** Partnership account number | 28099 4377 RZ0001 |
| **061** Fiscal period end (Year Month Day) | 2018-12-31 |

## Documents required to be attached to this T5013 FIN, Partnership Financial Return

1. The T5013 Summary, Summary of Partnership Income, and a copy of the T5013, Statement of Partnership Income, issued to partners and nominees or agents.
2. The GIFI schedules; 100, 125, 140 (when more than one schedule 125 is filed), and schedule 141 which is not required for investment clubs.
3. Schedule 1 (if you are an inactive partnership, see line 280 in Guide T4068 for more information) and Schedule 50.
4. Answer all of the following questions. For each **Yes** response, **attach** the schedule to the partnership return, unless otherwise instructed.

| Question | Line | 1 Yes | 2 No | Schedule or form |
|---|---|---|---|---|
| At any time during the fiscal period, was the partnership a member (directly, or indirectly through one or more partnerships) of another partnership? | 150 | | X | 9 |
| Has the partnership had any transactions, including sections 97 and 98, and subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents. | 162 | | X | T2058, T2059, and/or T2060 |
| Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents? | 171 | | X | T106 |
| Is the partnership required to file Form T1134 in respect of any foreign affiliates in the fiscal period? | 172 | | X | T1134 |
| Has the partnership made any charitable donations, gifts of cultural or ecological property, gifts of medicine, or federal, provincial, territorial, or municipal political contributions? | 202 | | X | 2 |
| Does the partnership have a permanent establishment in more than one jurisdiction? | 205 | | X | 5 |
| Has the partnership realized any capital gains or incurred any capital losses during the fiscal period? | 206 | | X | 6 |
| Does the partnership have any property that is eligible for capital cost allowance? | 208 | | X | 8 |
| Does the partnership have any resource-related deductions (excluding renounced expenditures)? | 212 | | X | 12 |
| Is the partnership allocating any investment tax credits (ITCs)? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners. | 231 | | X | Calculation and allocation |
| Did the partnership incur any scientific research and experimental development (SR&ED) expenditures? | 232 | | X | T661 |
| Did the partnership allocate renounced resource expenses to its members? | 252 | | X | 52 |
| Did the partnership own or hold specified foreign property where the total cost amount of all such property, at any time in the fiscal period, was more than CAN$100,000? | 259 | | X | T1135 |

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| | | | |
|---|---|---|---|
| 001 | **Partnership account number** 28099 4377 RZ0001 | 061 | **Fiscal period end** Year Month Day 2018-12-31 |

## Additional information

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Did the partnership use the international financial reporting standards (IFRS) when it prepared its financial statements? | 270 | | X |
| Was a slip issued to one or more nominees or agents? | 271 | | X |
| Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2? | 272 | | X |
| Does the partnership have one or more new nominees or agents? | 273 | | X |
| Did the partnership allocate any amount of income tax deducted at source? | 274 | | X |
| Did the partnership make any other election(s) under the Act during the fiscal period? If **Yes**, attach a copy of each election form to this return. | 275 | | X |
| Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed? If **Yes**, provide the business number(s) of the predecessor partnership(s): | 277 | | X |

278

279

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Was the partnership inactive throughout the fiscal period this information return applies to? If **Yes**, see Guide T4068 to verify your filing requirements. | 280 | X | |
| Did members of the partnership immigrate to Canada during the fiscal period? | 291 | | X |
| Did members of the partnership emigrate from Canada during the fiscal period? | 292 | | X |
| If the major business activity is construction, did you have any subcontractors during the fiscal period? | 295 | | X |
| Did the partnership report its farming or fishing income using the cash method? | 296 | | X |
| Is this a publicly traded partnership? | 297 | | X |
| If **Yes**, did the partnership issue T5008 information slips to report transactions of interests in the partnership? | 298 | | |

## Miscellaneous information

| Question | Line | 1 Yes | 2 No |
|---|---|---|---|
| Was an NR4 information return for tax deductions withheld at source filed for the fiscal period? | 301 | | X |
| If **Yes**, provide the non-resident account number: | 302 | | |
| If **Yes**, were NR4 slips issued? | 303 | | |
| Is this partnership a specified investment flow-through (SIFT) partnership? | 304 | | X |
| If **Yes**, enter the taxable non-portfolio earnings for the fiscal period: | 305 | | |
| If **Yes**, enter the tax payable under Part IX.1 for the fiscal period: | 306 | | |
| Enter the amount of the late filing penalty from line 307 of Schedule 52. | 307 | | |
| Amount of payment enclosed with this return: | 308 | | |

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| | | | |
|---|---|---|---|
| 001 | **Partnership account number** 28099 4377 RZ0001 | 061 | **Fiscal period end** Year Month Day 2018-12-31 |

## Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15) of the Act

| | |
|---|---|
| 400 Hydro One Indigenous Partnerships GP Inc. | 402 818381840RC0001 |
| Name of designated partner | Identification number |

## Additional information for tax shelters only

Principal promoter

| | | |
|---|---|---|
| 500 | 501 | 502 |
| Last name (print) | First name (print) | Identification number |

## Certification

| | | |
|---|---|---|
| I, 950 Tran | 951 Nancy | 954 VP, Corporate Tax |
| Last name (print) | First name (print) | Position or title |

certify that the information given on this form is correct and complete. I further certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as specifically disclosed in a statement attached to this return.

| | | |
|---|---|---|
| 955 2019-05-21 | | 956 (416) 345-6778 |
| Year Month Day | Signature of the authorized partner | Telephone number |

## Language of correspondence

Indicate your language of correspondence: 990 [X] 1 English [ ] 2 French

Personal information is collected under the Income Tax Act to administer tax, benefits, and related programs. It may also be used for any purpose related to the enforcement of the Act such as audit, compliance and collection activities. It may be shared or verified with other federal, provincial, territorial or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the Privacy Act, individuals have the right to access their personal information, request correction, or file a complaint to the Privacy Commissioner of Canada regarding the handling of the individual's personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at **canada.ca/cra-info-source**.

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# PARTNERSHIP'S BALANCE SHEET INFORMATION

**T5013 SCHEDULE 100**

| Partnership name | Partnership account Number | Fiscal period end Year Month Day | Original X / Amended |
|---|---|---|---|
| Niagara Reinforcement Limited Partnership | 28099 4377 RZ0001 | 2018-12-31 | Original: X |

Is this a NIL schedule? . . . . . 999 Yes [ ] No [X]

## Balance sheet information

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| | Total current assets | 1599 | + | 1,000.00 | |
| | Total tangible capital assets | 2008 | + | | |
| | Total accumulated amortization of tangible capital assets | 2009 | – | | |
| | Total intangible capital assets | 2178 | + | | |
| | Total accumulated amortization of intangible capital assets | 2179 | – | | |
| | Total long-term assets | 2589 | + | | |
| | * Assets held in trust | 2590 | + | | |
| | **Total assets** (mandatory field) | 2599 | = | 1,000.00 | |
| **Liabilities** | | | | | |
| | Total current liabilities | 3139 | + | | |
| | Total long-term liabilities | 3450 | + | | |
| | * Subordinated debt | 3460 | + | | |
| | * Amounts held in trust | 3470 | + | | |
| | **Total liabilities** (mandatory field) | 3499 | = | | |
| **Partner's capital** | | | | | |
| | **Total partners' capital** (mandatory field) | 3575 | + | 1,000.00 | |
| | **Total liabilities and partners' capital** | 3585 | = | 1,000.00 | |

* Generic item

# Current Assets

**SCHEDULE 100**

Form Identifier 1599

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **Current advances/loans/notes between the partners and the partnership** | | | | |
| | * Due from member(s)/general partner(s) | 1310 | | 1,000.00 | |
| | **Current advances/loans/notes between the partners and the partnership** | | + | 1,000.00 | |
| | **Total current assets** | 1599 | = | 1,000.00 | |

***** Generic item

# Partner's capital

**SCHEDULE 100**

GIFI Code 3575

| Account | Description | GIFI | | Current year | Prior year |
|---|---|---|---|---|---|
| | **General partners' capital** | | | | |
| | General partners' capital beginning balance | 3551 | + | 1.00 | |
| | **General partners' capital ending balance** | 3560 | = | 1.00 | |
| | **Limited partners' capital** | | | | |
| | Limited partners' capital beginning balance | 3561 | + | 999.00 | |
| | **Limited partners' capital ending balance** | 3571 | + | 999.00 | |
| | **Total partners' capital** | 3575 | = | 1,000.00 | |

***** Generic item

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# Financial Statement Notes Checklist

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**T5013**
**Schedule 141**

| **Partnership name** | **Partnership account number** | **Fiscal period end** Year Month Day | |
|---|---|---|---|
| Niagara Reinforcement Limited Partnership | 28099 4377 RZ0001 | 2018-12-31 | [X] Original [ ] Amended |

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- For more information, see Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*, and Guide RC4088, *General Index of Financial Information (GIFI).*
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, *Partnership Financial Return*.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected with the partnership? * . . . . . **097** 1 Yes [X] 2 No [ ]

**Note:** If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.

* A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the accountant's highest level of involvement: **198**

- Completed an auditor's report . . . . . 1 [ ]
- Completed a review engagement report . . . . . 2 [ ]
- Conducted a compilation engagement . . . . . 3 [ ]

## Part 3 – Reservations

If you selected option 1 or option 2 **in part 2** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

## Part 4 – Other information (continued on page 2)

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: **110**

- Prepared the information return (financial statements prepared by client) . . . . . 1 [ ]
- Prepared the information return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [ ] 2 No [X]

If **yes**, answer the following four questions:

- Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [ ]
- Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [ ]
- Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [ ]
- Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [ ] 2 No [ ]

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below . . . . . **108** 1 Yes [ ] 2 No [X]

- Are you filing joint venture(s) financial statements? . . . . . **109** 1 Yes [ ] 2 No [ ]

| Partnership account number | Fiscal period end Year Month Day |
|---|---|
| 28099 4377 RZ0001 | 2018-12-31 |

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## Part 4 – Other information (continued)

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

| | | In net income Increase (decrease) | | In other comprehensive income Increase (decrease) |
|---|---|---|---|---|
| Property, plant and equipment | 210 | | 211 | |
| Intangible assets | 215 | | 216 | |
| Investment property | 220 | | | |
| Biological assets | 225 | | | |
| Financial instruments | 230 | | 231 | |
| Other | 235 | | 236 | |

**Financial instruments**

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the partnership apply hedge accounting during the fiscal period? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the partnership discontinue hedge accounting during the fiscal period? . . . . . **260** 1 Yes [ ] 2 No [X]

**Adjustments to opening partners' capital**

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.



See the privacy notice on your return.

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# Partner's Ownership and Account Activity

**Protected B** when completed

**T5013**
**Schedule 50**

| Partnership name | Partnership account number | Fiscal period end (Year Month Day) | |
|---|---|---|---|
| Niagara Reinforcement Limited Partnership | 280994377RZ0001 | 2018-12-31 | X Original / ☐ Amended |

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

| | | |
|---|---|---|
| **Number of partners** | 010 | 2 |
| **Number of partners who disposed of all, or part of, their partnership interest** | 011 | |
| **Number of nominees or agents** | 012 | |
| **Total of all amounts from line 220** | 015 | |

**Partner 1**

| 100 Partner name | 101 Partner identification number | 105 Type of partner | 106 Partner code | 107 Percentage (%) of partner's interest | 110 Did the partner dispose of an interest during the fiscal period? | 220 Partner's share of the net income (loss) | 300 Cost base |
|---|---|---|---|---|---|---|---|
| Hydro One Networks Inc. | 870865821RC0001 | 2 | 0 | 99.9000 | ☐ Yes X No | | 0.00 |

| 310 Cost of units acquired during the fiscal period | 320 Partner's share of the previous fiscal period's net income (loss) | 330 Capital contributions in the fiscal period | 340 Withdrawals in the fiscal period | 350 Other adjustment | 410 Partner's share of the fiscal period's net income | 420 Partner's share in certain reductions of resource expenses for the fiscal period | 430 Non-arm's length debt owing and/or benefits receivable |
|---|---|---|---|---|---|---|---|
| 999.00 | | | | | | | |

**Partner 2**

| 100 Partner name | 101 Partner identification number | 105 Type of partner | 106 Partner code | 107 Percentage (%) of partner's interest | 110 Did the partner dispose of an interest during the fiscal period? | 220 Partner's share of the net income (loss) | 300 Cost base |
|---|---|---|---|---|---|---|---|
| Hydro One Indigenous Partnerships GP Inc. | 818381840RC0001 | 2 | 2 | 0.1000 | ☐ Yes X No | | 0.00 |

| 310 Cost of units acquired during the fiscal period | 320 Partner's share of the previous fiscal period's net income (loss) | 330 Capital contributions in the fiscal period | 340 Withdrawals in the fiscal period | 350 Other adjustment | 410 Partner's share of the fiscal period's net income | 420 Partner's share in certain reductions of resource expenses for the fiscal period | 430 Non-arm's length debt owing and/or benefits receivable |
|---|---|---|---|---|---|---|---|
| 1.00 | | | | | | | |

Approval code: RC-18-P006

**Protected B** when completed

| Partner 3 | Ownership | | | | | Fiscal period's income (loss) allocation | Account activity |
|---|---|---|---|---|---|---|---|
| 100 | 101 | 105 | 106 | 107 | 110 | 220 | 300 |
| Partner name | Partner identification number | Type of partner | Partner code | Percentage (%) of partner's interest | Did the partner dispose of an interest during the fiscal period? | Partner's share of the net income (loss) | Cost base |
| | | | | | Yes No | | |

| Account activity (continued) | | | | | At-risk amount (ARA) (for limited partners only) | | |
|---|---|---|---|---|---|---|---|
| 310 | 320 | 330 | 340 | 350 | 410 | 420 | 430 |
| Cost of units acquired during the fiscal period | Partner's share of the previous fiscal period's net income (loss) | Capital contributions in the fiscal period | Withdrawals in the fiscal period | Other adjustment | Partner's share of the fiscal period's net income | Partner's share in certain reductions of resource expenses for the fiscal period | Non-arm's length debt owing and/or benefits receivable |
| | | | | | | | |

| Partner 4 | Ownership | | | | | Fiscal period's income (loss) allocation | Account activity |
|---|---|---|---|---|---|---|---|
| 100 | 101 | 105 | 106 | 107 | 110 | 220 | 300 |
| Partner name | Partner identification number | Type of partner | Partner code | Percentage (%) of partner's interest | Did the partner dispose of an interest during the fiscal period? | Partner's share of the net income (loss) | Cost base |
| | | | | | Yes No | | |

| Account activity (continued) | | | | | At-risk amount (ARA) (for limited partners only) | | |
|---|---|---|---|---|---|---|---|
| 310 | 320 | 330 | 340 | 350 | 410 | 420 | 430 |
| Cost of units acquired during the fiscal period | Partner's share of the previous fiscal period's net income (loss) | Capital contributions in the fiscal period | Withdrawals in the fiscal period | Other adjustment | Partner's share of the fiscal period's net income | Partner's share in certain reductions of resource expenses for the fiscal period | Non-arm's length debt owing and/or benefits receivable |
| | | | | | | | |

| Partner 5 | Ownership | | | | | Fiscal period's income (loss) allocation | Account activity |
|---|---|---|---|---|---|---|---|
| 100 | 101 | 105 | 106 | 107 | 110 | 220 | 300 |
| Partner name | Partner identification number | Type of partner | Partner code | Percentage (%) of partner's interest | Did the partner dispose of an interest during the fiscal period? | Partner's share of the net income (loss) | Cost base |
| | | | | | Yes No | | |

| Account activity (continued) | | | | | At-risk amount (ARA) (for limited partners only) | | |
|---|---|---|---|---|---|---|---|
| 310 | 320 | 330 | 340 | 350 | 410 | 420 | 430 |
| Cost of units acquired during the fiscal period | Partner's share of the previous fiscal period's net income (loss) | Capital contributions in the fiscal period | Withdrawals in the fiscal period | Other adjustment | Partner's share of the fiscal period's net income | Partner's share in certain reductions of resource expenses for the fiscal period | Non-arm's length debt owing and/or benefits receivable |
| | | | | | | | |

See the privacy notice on your return.

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le: 2018-12-31 (YYYY MM DD / AAAA MM JJ)

# T5013

## Statement of Partnership Income
## État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON  M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

| | | |
|---|---|---|
| 002 | Partner code / Code de l'associé | 0 |
| 003 | Country code / Code du pays | CAN |
| 004 | Recipient type / Genre de bénéficiaire | 3 |
| 001 | Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | 280994377RZ0001 |
| 010 | Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | |
| 020 | Total business income (loss) / Total du revenu (de la perte) d'entreprise | |
| 006 | Partner's identification number / Numéro d'identification de l'associé | 870865821RC0001 |
| 005 | Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes | 99.900000 |
| 030 | Total capital gains (losses) / Total des gains (pertes) en capital | |
| 040 | Capital cost allowance / Déduction pour amortissement | |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales

Hydro One Networks Inc.
483 Bay Street
7th Floor, South Tower
Toronto ON  M5G 2P5

| Box / Case | Code | Amount – Montant |
|---|---|---|
| 105 | | 999.00 |
| 106 | | 999.00 |

Box – Case / Code / Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli



**For Tax Centre 1**
**Pour le Centre fiscal 1**

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le (YYYY MM DD / AAAA MM JJ): 2018-12-31

# T5013

## Statement of Partnership Income
## État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

| | | |
|---|---|---|
| 002 | Partner code / Code de l'associé | 2 |
| 003 | Country code / Code du pays | CAN |
| 004 | Recipient type / Genre de bénéficiaire | 3 |
| 001 | Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | 280994377RZ0001 |
| 010 | Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | |
| 020 | Total business income (loss) / Total du revenu (de la perte) d'entreprise | |
| 006 | Partner's identification number / Numéro d'identification de l'associé | 818381840RC0001 |
| 005 | Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes | 0.100000 |
| 030 | Total capital gains (losses) / Total des gains (pertes) en capital | |
| 040 | Capital cost allowance / Déduction pour amortissement | |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales

► Hydro One Indigenous Partnerships GP Inc.

483 Bay Street
7th Floor, South Tower
Toronto ON M5G 2P5

| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

| Box – Case | Code | Amount – Montant | Box – Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| | | | | | |

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Consultez l'avis de confidentialité dans votre déclaration



T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

**For Tax Centre 1**
**Pour le Centre fiscal 1**

Canada Revenue Agency — Agence du revenu du Canada

Fiscal period end / Exercice se terminant le (YYYY MM DD / AAAA MM JJ): 2018-12-31

# T5013

**Statement of Partnership Income**
**État des revenus d'une société de personnes**

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON  M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

| Partner code / Code de l'associé | Country code / Code du pays | Recipient type / Genre de bénéficiaire |
|---|---|---|
| 002 — 0 | 003 — CAN | 004 — 3 |

| | | |
|---|---|---|
| Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | 001 | 280994377RZ0001 |
| Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | 010 | |
| Total business income (loss) / Total du revenu (de la perte) d'entreprise | 020 | |
| Partner's identification number / Numéro d'identification de l'associé | 006 | 870865821RC0001 |
| Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes | 005 | 99.900000 |
| Total capital gains (losses) / Total des gains (pertes) en capital | 030 | |
| Capital cost allowance / Déduction pour amortissement | 040 | |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales

Hydro One Networks Inc.
483 Bay Street
7th Floor, South Tower
Toronto ON  M5G 2P5

| Box / Case | Code | Amount – Montant | Box / Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| 105 | | 999 00 | 106 | | 999 00 |

| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Attach to your income tax return 2**
**Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2**

**See recipient instructions**
**Voir les instructions du bénéficiaire**



T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period end / Exercice se terminant le: YYYY MM DD 2018-12-31 AAAA MM JJ

# T5013

**Statement of Partnership Income**
**État des revenus d'une société de personnes**

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

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|---|---|---|
| 002: 0 | 003: CAN | 004: 3 |

| | |
|---|---|
| 001 Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | 280994377RZ0001 |
| 010 Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | |
| 020 Total business income (loss) / Total du revenu (de la perte) d'entreprise | |
| 006 Partner's identification number / Numéro d'identification de l'associé | 870865821RC0001 |
| 005 Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes | 99.900000 |
| 030 Total capital gains (losses) / Total des gains (pertes) en capital | |
| 040 Capital cost allowance / Déduction pour amortissement | |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

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Toronto ON M5G 2P5

| Box / Case | Code | Amount – Montant | Box / Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| 105 | | 999 00 | 106 | | 999 00 |

Box – Case | Code | Other information – Autres renseignements

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Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Keep this slip for your records 3**
**Bénéficiaire – Conservez pour vos dossiers 3**

**See recipient instructions**
**Voir les instructions du bénéficiaire**



T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency | Agence du revenu du Canada

# T5013

**Statement of Partnership Income**
**État des revenus d'une société de personnes**

Fiscal period end / Exercice se terminant le (YYYY MM DD / AAAA MM JJ): 2018-12-31

Filer's name and address – Nom et adresse du déclarant
Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

| | | |
|---|---|---|
| 002 | Partner code – Code de l'associé | 2 |
| 003 | Country code – Code du pays | CAN |
| 004 | Recipient type – Genre de bénéficiaire | 3 |
| 001 | Partnership account number (15 characters) – Numéro de compte de la société de personnes (15 caractères) | 280994377RZ0001 |
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| 006 | Partner's identification number – Numéro d'identification de l'associé | 818381840RC0001 |
| 005 | Partner's share (%) of partnership – Part de l'associé (%) dans la société de personnes | 0.100000 |
| 030 | Total capital gains (losses) – Total des gains (pertes) en capital | |
| 040 | Capital cost allowance – Déduction pour amortissement | |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Indigenous Partnerships GP Inc.
483 Bay Street
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Toronto ON M5G 2P5

| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

| Box / Case | Code | Amount – Montant | Box / Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| | | | | | |

See the privacy notice on your return
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**For Recipient – Attach to your income tax return 2**
**Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2**

**See recipient instructions**
**Voir les instructions du bénéficiaire**



T5013 (15) **Protected B** when completed – **Protégé B** une fois rempli

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period end / Exercice se terminant le — YYYY MM DD / AAAA MM JJ: 2018-12-31

# T5013

## Statement of Partnership Income
## État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON  M5G 2P5

Tax shelter identification number (see **statement** on reverse side *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

| | | |
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| 030 | Total capital gains (losses) / Total des gains (pertes) en capital | |
| 040 | Capital cost allowance / Déduction pour amortissement | |

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Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Indigenous Partnerships GP Inc.
483 Bay Street
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| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

| Box – Case | Code | Amount – Montant | Box – Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| | | | | | |

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**For Recipient – Keep this slip for your records 3**
**Bénéficiaire – Conservez pour vos dossiers 3**

**See recipient instructions**
**Voir les instructions du bénéficiaire**

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period end / Exercice se terminant le: YYYY MM DD / AAAA MM JJ 2018-12-31

# T5013

## Statement of Partnership Income
## État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON  M5G 2P5

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

| Partner code / Code de l'associé | Country code / Code du pays | Recipient type / Genre de bénéficiaire |
|---|---|---|
| 002: 0 | 003: CAN | 004: 3 |

| Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | Total business income (loss) / Total du revenu (de la perte) d'entreprise |
|---|---|---|
| 001: 280994377RZ0001 | 010: | 020: |

| Partner's identification number / Numéro d'identification de l'associé | Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes | Total capital gains (losses) / Total des gains (pertes) en capital | Capital cost allowance / Déduction pour amortissement |
|---|---|---|---|
| 006: 870865821RC0001 | 005: 99.900000 | 030: | 040: |

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initiales – Initiales

Hydro One Networks Inc.
483 Bay Street
7th Floor, South Tower
Toronto ON  M5G 2P5

| Box / Case | Code | Amount – Montant | Box / Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| 105 | | 999 00 | 106 | | 999 00 |

| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

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Consultez l'avis de confidentialité dans votre déclaration

Canada Revenue Agency / Agence du revenu du Canada

# T5013

**Statement of Partnership Income**
**État des revenus d'une société de personnes**

Fiscal period end / Exercice se terminant le (YYYY MM DD / AAAA MM JJ): 2018-12-31

Filer's name and address – Nom et adresse du déclarant

Niagara Reinforcement Limited Partnership
483 Bay Street, 8th Floor, South Tower
Toronto ON  M5G 2P5

Tax shelter identification number (see **statement** on reverse side *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

| | | |
|---|---|---|
| 002 | Partner code / Code de l'associé | 2 |
| 003 | Country code / Code du pays | CAN |
| 004 | Recipient type / Genre de bénéficiaire | 3 |
| 001 | Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères) | 280994377RZ0001 |
| 010 | Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire | |
| 020 | Total business income (loss) / Total du revenu (de la perte) d'entreprise | |
| 006 | Partner's identification number / Numéro d'identification de l'associé | 818381840RC0001 |
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7th Floor, South Tower
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| Box – Case | Code | Other information – Autres renseignements |
|---|---|---|
| | | |

| Box / Case | Code | Amount – Montant | Box / Case | Code | Amount – Montant |
|---|---|---|---|---|---|
| | | | | | |

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Canada Revenue Agency / Agence du revenu du Canada

# Summary of Partnership Income
# Sommaire des revenus d'une société de personnes

**Protected B / Protégé B**
when completed / une fois rempli

**T5013** Summary / Sommaire

**Fill out this summary and related slips using the instructions in guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.**

**Remplissez ce sommaire et les feuillets connexes en suivant les instructions du guide T4068, *Guide pour la déclaration de renseignements des sociétés de personnes (formulaires T5013)*.**

**Do not use this area. N'inscrivez rien ici.**

50 | 1616

**For the fiscal period – Pour l'exercice**

**Start / Début** 2018-09-19 (Year Month Day / Année Mois Jour)

**End / Fin** 2018-12-31 (Year Month Day / Année Mois Jour)

**Partnership's account number / Numéro de compte de la société de personnes:** 28099 4377 RZ0001

**Name of the partnership – Nom de la société de personnes:** Niagara Reinforcement Limited Partnership

**Postal or ZIP code / Code postal ou ZIP:** M5G 2P5

**Are you a nominee or agent? (tick if yes and provide the following information)**
**Êtes-vous un mandataire ou un agent? (cochez si oui et fournir les renseignements qui suivent)** ☐

**Name of the nominee or agent – Nom du mandataire ou de l'agent:**

**Postal or ZIP code / Code postal ou ZIP:**

**Nominee or agent's account number / Numéro de compte du mandataire ou de l'agent:**

**Is the partnership a tax shelter? (tick if yes) / La société de personnes est-elle un abri fiscal? (cochez si oui)** ☐

**If yes, provide the tax shelter identification number / Si oui, fournir le numéro d'identification de l'abri fiscal:**

## Totals from T5013 slips – Totaux des feuillets T5013

Total number of T5013 information slips attached: / Nombre total de feuillets de renseignements T5013 joints : **009** 2

| | | |
|---|---|---|
| Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire | **010** | |
| Total business income (loss) – Total du revenu (de la perte) d'entreprise | **020** | |
| Total capital gains (losses) – Total des gains (pertes) en capital | **030** | |
| Capital cost allowance – Déduction pour amortissement | **040** | |

Complete the six generic boxes identified below taken from the T5013 slips – Remplissez les lignes ci-dessous pour les six cases génériques qui parviennent des feuillets T5013

| | | |
|---|---|---|
| Canadian and foreign net rental income (loss) – Revenu net (perte nette) de location canadien et étranger | **110** | |
| Professional income (loss) – Revenu (perte) de profession libérale | **120** | |
| Renounced Canadian exploration expenses – Frais renoncés d'exploration au Canada | **190** | |
| Renounced Canadian development expenses – Frais renoncés d'aménagement au Canada | **191** | |
| Expenses qualifying for an ITC – Frais admissibles aux fins du CII | **194** | |
| Total carrying charges – Total des frais financiers | **210** | |

Person to contact about this return / Personne-ressource que nous pouvons contacter à propos de cette déclaration: **076** Tran, Nancy

Area code / Indicatif régional – Telephone number / Numéro de téléphone: **078** (416) 345-6778

Extension / Numéro de poste:

**Certification – Attestation**

I certify that the information given in this return and related summary and slips is correct and complete.

J'atteste que les renseignements fournis dans cette déclaration de renseignements et sur tous les feuillets connexes sont exacts et complets.

| Date | Signature of authorized person – Signature d'une personne autorisée | Position or office – Poste ou titre |
|---|---|---|
| 2019-05-21 | | VP, Corporate Tax |

Prepared by – Preparé par: 

Date: 2019-05-21

# Z-FACTOR CLAIMS

At this time, NRLP is not seeking recovery of any material costs associated with unforeseen events as described in section 2.8.12 of the Filing Requirements.

# CAPITAL STRUCTURE/COST OF CAPITAL

## 1. INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing NRLP's capital requirements for the 2020 to 2024 Revenue Cap IR period.

The cost of capital as described in this Exhibit has been reflected in the revenue requirements for 2020. NRLP anticipates updating the revenue requirement for the 2020 Test Year when the OEB releases its 2020 cost of capital parameters. This issuance would reflect the OEB-approved 2020 return on equity ("ROE"), deemed short-term debt rate and the deemed long-term debt rate to be used for custom IR applications with effective dates in 2020.

Currently, NRLP does not have any actual existing debt with third-party market rates. Following the transfer of assets on September 18, 2019, NRLP issued a note in the amount of $66.9 million representing 56% of NRLP's rate base, bearing interest at 4.13%. This rate reflects the OEB's deemed long-term debt rate for 2019[1]. This note is planned to be refinanced during 2020 with debt issued by NRLP to Hydro One Inc. or an affiliate. The refinancing debt issue will mirror the terms included in an actual debt issue planned to be issued by Hydro One Inc. to third party public debt investors. The timing of the refinancing is expected to be completed at the same time as B2M LP's debt refinancing. Combining the issues will help to lower overall issue costs for ratepayers. This is expected to occur in mid-2020.

To reflect the terms of the external issue in its revenue requirement, NRLP proposes to make a one-time update of the cost of long-term debt at the first annual update of rates

[1] See OEB Letter Re: 2019 Cost of Capital Parameters dated November 22, 2018.

for 2021. This update will include the actual market rate achieved on the long-term debt to be issued in 2020.

## 2. CAPITAL STRUCTURE

NRLP's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base, where the 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt.

This structure is consistent with the OEB's report on the Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084), and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

### 2.1 COST OF CAPITAL SUMMARY

The cost of capital as described in this Exhibit has been reflected in the revenue requirement for the 2020 Test Year. NRLP's proposed 2020 cost of capital is presented in Table 1:

**Table 1 - 2020 Cost of Capital**

| 2020 | | | | |
|---|---|---|---|---|
| **Amount of Deemed Return** | **($M)** | **%** | **Cost Rate (%)** | **Return ($M)** |
| Long-term debt | 65.99 | 56% | 3.82% | 2.52 |
| Short-term debt | 4.71 | 4% | 2.82% | 0.13 |
| Common equity | 47.14 | 60% | 8.98% | 4.23 |
| **Total** | **117.84** | **100%** | **5.84%** | **6.89** |

When the OEB releases its 2020 cost of capital parameters, NRLP will file with the Board an update to the revenue requirement for the 2020 Test Year to reflect the updates for the ROE, the deemed short-term debt rate and the deemed long-term debt rate for custom IR applications with effective dates in 2020.  NRLP proposes that the 2020 cost of capital parameters established at that time be then used to determine the final revenue requirements for the 2020 Test Year.

The Test year debt and equity summary schedules are provided at Exhibit G, Tab 1, Schedule 3.

The OEB is expected to issue its Decision and Order before NRLP issues actual debt to finance the long-term debt component of its rate base. NRLP proposes a one-time update to the cost of long-term debt, at the first annual update for rates starting in 2021, to reflect the actual market rate achieved on the long-term debt that it will issue.

### 2.1.1 RETURN ON COMMON EQUITY

NRLP's evidence reflects a ROE of 8.98% as a placeholder for 2020 based on the Cost of Capital Parameters released by the OEB on November 22, 2018, for rates effective January 1, 2019. It is calculated according to the OEB's formulaic approach in Appendix B of the Cost of Capital for Ontario's Regulated Utilities report, dated December 11, 2009 (EB-2009-0084).

As set out above, the Applicant will update the equity cost of capital for the 2020 Test Year by using the 2020 ROE to be released by the OEB in the fall of 2019.

### 2.1.2 DEEMED SHORT-TERM DEBT

The OEB has determined that the deemed amount of short-term debt that should be factored into rate-setting be fixed at 4% of rate base. The deemed short-term rate of 2.82% is being used by NRLP as a placeholder for 2020 and is based on the September 2018 average three-month bankers' acceptance rate of 1.923% and the 0.9% average annual spread from the Cost of Capital Parameters released by the OEB on November 22, 2018, for rates effective January 1, 2019.

NRLP will update the short-term debt rate for the 2020 Test year based on the 2020 deemed short-term debt rate to be released by the OEB in the fall of 2019.

### 2.1.3 LONG-TERM DEBT

The OEB has determined that the deemed amount of long-term debt that should be factored into rate-setting be fixed at 56% of rate base, consistent with the OEB's report on the Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084). The forecast weighted average long-term debt rate is calculated to be 3.82% for 2020.

NRLP will update the long-term debt rate for the 2020 Test year based on NRLP's weighted average of the OEB's deemed long-term debt rate for 2020 and the September 2019 Consensus Forecast, along with the proposed update of the return on common equity and deemed short-term interest rate. Consistent with the OEB's policy, stated on page 54 of its Cost of Capital report, the deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

## 3. COST OF LONG-TERM DEBT

### 3.1 NRLP LONG-TERM DEBT

Hydro One Inc. provides treasury services to NRLP. NRLP plans to issue debt to Hydro One Inc. to reflect debt issued by Hydro One Inc. to third-party public debt investors. Hydro One Inc. plans to issue debt to third party public debt investors at the same time that B2M LP's debt refinancing will be done in mid-2020, depending on market conditions at the time. Third-party public debt investors hold all of the long-term debt issued by Hydro One Inc. The debt portfolio for NRLP is detailed in Exhibit G, Tab 1, Schedule 3.

### 3.2 CREDIT RATINGS

As an issuing entity, Hydro One Inc. obtains credit ratings from credit rating agencies as a requirement to issue medium-term notes in the Canadian public debt markets. Table 2 lists the credit ratings of Hydro One Inc.'s debt obligations by DBRS, Moody's Investors Service and Standard & Poor's Rating Services:

**Table 2 - Credit Ratings for Hydro One Inc.**

| Rating Agency | Short-term Debt | Long-term Debt |
|---|---|---|
| **Standard & Poor's Rating Services (S&P)** | A-1(low) | A- |
| **DBRS** | R-1(low) | A(high) |
| **Moody's Investors Service (Moody's)** | Prime-2 | Baa1 |

The most recent rating agency reports are available in Hydro One Transmission's EB-2019-0082 proceeding at Exhibit A, Tab 6, Schedule 3.

### 3.3 COST OF LONG-TERM DEBT

The long-term debt rate for 2020 is calculated as the weighted average cost rate of 4.13% on its deemed long-term debt until April 30, 2020 (based on 2019 OEB cost of capital parameters), and forecast debt planned to be issued in 2020. The proposed weighted average long-term debt rate for 2020, using this methodology, is 3.82%. Details used in the calculation of the forecast long-term debt rate are presented at Exhibit G, Tab 1, Schedule 2, Page 1.

### 3.4 FORECAST DEBT

The OEB has determined in its Cost of Capital Report that the rate for new debt that is held by a third-party public debt investor will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

NRLP's planned borrowing requirement in 2020 is $66.0 million, based on its most recent forecast. NRLP's borrowing requirements are determined based on its rate base and capital structure as discussed in Section 2.

For the purpose of this application, NRLP's evidence reflects a long-term debt rate of 3.82%, as a placeholder for 2020. From January to April 2020, the OEB's deemed long-term debt for 2019 of 4.13% is applied and, from April 30, 2020, to December 31, 2024, NRLP has applied the long-term debt rate based on the forecast for new long-term debt rate calculation for 2020, reflecting the April 2019 Consensus Forecasts and the average of indicative new issue spreads for Hydro One Inc. for April 2019.

Table 3 lists the fixed-rate notes that Hydro One Inc. plans to issue for NRLP in 2020, as shown in lines 2 to 3 of Exhibit G, Tab 1, Schedule 2, page 1.

**Table 3 - Forecast Debt Issues for 2020**

| Principal Amount ($Millions) | Term (Years) | Coupon |
|---|---|---|
| 22.0 | 5 | 2.91% |
| 22.0 | 10 | 3.42% |
| 22.0 | 30 | 4.06% |

NRLP has calculated the weighted average debt rate to be 3.82% for 2020 and the forecast new long-term debt rate of 3.63% for 2021, as shown in Exhibit G, Tab 1, Schedule 2, page 1 and 2, respectively.

NRLP assumes that for rates effective January 1, 2020, the forecast interest rate for NRLP's debt issues will be updated based on the September 2019 Consensus Forecasts and the average of indicative new issue spreads for September 2019 that will be obtained from the Hydro One Medium Term Note ("MTN") dealer group for each planned issuance term.

The future financing rate on 100% of NRLP's long-term debt in 2020 is unknown and could have a material impact on NRLP's financial performance if not accounted for. NRLP proposes to update the cost of long-term debt at the first annual update for rates in 2021, to reflect the actual market rate achieved on the long-term debt it will issue. Based on the current assumed forecast rates, the cost of debt for 2021 would be 3.63%.

### 3.5 INTEREST RATES ON 2020 FORECAST DEBT ISSUES

NRLP's borrowing will be financed at market rates applicable to Hydro One Inc. Table 4 summarizes the derivation of the forecast Hydro One Inc. yields for each of the planned issuance terms for 2020.

**Table 4 - Forecast Yield for 2020 Issuance Terms**[2]

| | **2020** | | |
|---|---|---|---|
| | **5-year** | **10-year** | **30-year** |
| **Government of Canada** | 1.95% | 2.10% | 2.39% |
| **Hydro One Spread** | 0.96% | 1.32% | 1.67% |
| **Forecast Hydro One Yield** | 2.91% | 3.42% | 4.06% |

Each rate comprises the forecast Government of Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2020 is based on the average of the three-month and 12-month forecast from the April 2019 Consensus Forecast. The ten-year Government of Canada bond yield forecast for 2020 is based on the April 2019 Long-Term Consensus Forecast. The

[2] NRLP plans to update the forecast yields to reflect the September 2019 Consensus Forecasts and the average of indicative new issue spreads for September 2019 that will be obtained from the Hydro One Inc. MTN dealer group for each planned issuance term.

five-year Government of Canada bond yield forecasts are derived by subtracting the April 2019 average spreads (five-year to ten-year for the five-year forecast) from the ten-year Government of Canada bond yield forecast. The thirty-year Government of Canada bond yield forecasts are derived by adding the April 2019 average spreads (30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for April 2019 obtained from the Company's MTN dealer group for each planned issuance term.

NRLP assumes that, for rates effective January 1, 2020, the forecast interest rate for Hydro One Inc.'s debt issues will be based on the September 2019 Consensus Forecasts and the average of indicative new issue spreads for September 2019 that will be obtained from the Hydro One Inc. MTN dealer group for each planned issuance term.

### 3.6 TREASURY OM&A COSTS

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage NRLP's daily liquidity position, control cash, and manage the company's bank accounts;
- settle all transactions and manage relationships with creditors; and
- communicate with debt investors, banks and credit rating agencies.

Treasury OM&A costs are provided in the long-term debt schedules for Test year in Exhibit G, Tab 1, Schedule 2 and are summarized in Table 5:

**Table 5 - Forecast Treasury OM&A Costs**

| Year | Amount ($Millions) | Line | Page |
|---|---|---|---|
| 2020 | 0.02 | 6 | 1 |

### 3.7 OTHER FINANCING-RELATED FEES

Column (e) of Exhibit G, Tab 1, Schedule 2 ("Premium, Discount and Expenses") represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues and re-openings of issues relative to par, and hedge gains or losses.

Other financing-related fees include the Transmission allocation of Hydro One Inc.'s standby credit facility, annual credit rating agency, filing fees to security regulators, letters of credit, banking, custodial and trustee fees. These fees are summarized in Table 6 and are also provided in the long term debt schedules for the Bridge and Test years in Exhibit G, Tab 1, Schedule 2:

**Table 6 - Forecast Other Financing-Related Fees**

| Year | Amount ($Millions) | Line | Page |
|---|---|---|---|
| 2020 | 0.05 | 7 | 1 |

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
Test Year (2020)
Year ending December 31

| Line No. | Offering Date | Coupon Rate | Maturity Date | Principal Amount Offered ($Millions) | Premium Discount and Expenses ($Millions) | Net Capital Employed Total Amount ($Millions) | Net Capital Employed Per $100 Principal Amount (Dollars) | Effective Cost Rate | Total Amount Outstanding at 12/31/2019 ($Millions) | Total Amount Outstanding at 12/31/2020 ($Millions) | Avg. Monthly Averages ($Millions) | Carrying Cost ($Millions) | Projected Average Embedded Cost Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| 1 | 18-Sep-19 | 4.13% | 30-Apr-20 | 66.88 | 0.00 | 66.88 | 100.00 | 4.13% | 66.88 | 0.00 | 20.58 | 0.85 | |
| 2 | 30-Apr-20 | 2.91% | 30-Apr-25 | 22.00 | 0.11 | 21.89 | 99.50 | 3.02% | 0.00 | 22.00 | 15.23 | 0.46 | |
| 3 | 30-Apr-20 | 3.42% | 30-Apr-30 | 22.00 | 0.11 | 21.89 | 99.50 | 3.48% | 0.00 | 22.00 | 15.23 | 0.53 | |
| 4 | 30-Apr-20 | 4.06% | 30-Apr-50 | 22.00 | 0.11 | 21.89 | 99.50 | 4.09% | 0.00 | 22.00 | 15.23 | 0.62 | |
| 5 | | **Subtotal** | | | | | | | 66.88 | 66.00 | 66.27 | 2.46 | |
| 6 | | Treasury OM&A costs | | | | | | | | | | 0.02 | |
| 7 | | Other financing-related fees | | | | | | | | | | 0.05 | |
| 8 | | **Total** | | | | | | | 66.88 | 66.00 | 66.27 | 2.53 | 3.82% |

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
2021
Year ending December 31

| Line No. | Offering Date | Coupon Rate | Maturity Date | Principal Amount Offered ($Millions) | Premium Discount and Expenses ($Millions) | Capital Employed Total Amount ($Millions) | Capital Employed Per $100 Principal Amount (Dollars) | Effective Cost Rate | Total Amount Outstanding at 12/31/2020 ($Millions) | Total Amount Outstanding at 12/31/2021 ($Millions) | Avg. Monthly Averages ($Millions) | Carrying Cost ($Millions) | Projected Average Embedded Cost Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
| 1 | 30-Apr-20 | 2.912% | 30-Apr-25 | 22.0 | 0.1 | 21.9 | 99.50 | 3.02% | 22.0 | 22.0 | 22.0 | 0.7 | |
| 2 | 30-Apr-20 | 3.418% | 30-Apr-30 | 22.0 | 0.1 | 21.9 | 99.50 | 3.48% | 22.0 | 22.0 | 22.0 | 0.8 | |
| 3 | 30-Apr-20 | 4.059% | 30-Apr-50 | 22.0 | 0.1 | 21.9 | 99.50 | 4.09% | 22.0 | 22.0 | 22.0 | 0.9 | |
| 4 | | **Subtotal** | | | | | | | 66.0 | 66.0 | 66.0 | 2.3 | |
| 5 | | Treasury OM&A costs | | | | | | | | | | 0.0 | |
| 6 | | Other financing-related fees | | | | | | | | | | 0.1 | |
| 7 | | **Total** | | | | | | | 66.0 | 66.0 | 66.0 | 2.4 | 3.63% |

**Niagara Reinforcement Limited Partnership**
Summary of Cost of Capital
Test Year 2020
Utility Capital Structure
Year Ending December 31
($ Millions)

| | | 2020 | | | |
|---|---|---|---|---|---|
| **Line No.** | **Particulars** | **($M)** | **%** | **Cost Rate (%)** | **Return ($M)** |
| | | (a) | (b) | (c) | (d) |
| I | Long-term debt | 66.0 | 56.0% | 3.8% | 2.5 |
| 2 | Short-term debt | 4.7 | 4.0% | 2.8% | 0.1 |
| 3 | Deemed long-term debt | 0.0 | 0.0% | 3.8% | 0.0 |
| 4 | Total debt | 70.7 | 60.0% | 3.8% | 2.7 |
| 5 | Common equity | 47.1 | 40.0% | 9.0% | 4.2 |
| 6 | Total rate base | 117.8 | 100.0% | 5.8% | 6.9 |

# REGULATORY ACCOUNTS

## 1. INTRODUCTION

The purpose of this Exhibit is to provide a description of NRLP's regulatory accounts.

All of the proposed regulatory accounts will be established consistent with the OEB's requirements as set out in the Accounting Procedures Handbook, subsequent OEB direction, or as per specific requests initiated by NRLP. The forecasted outstanding regulatory account balances are summarized in Table 1:

**Table 1 - Summary of Regulatory Account Balances ($ Millions)**

| Description | US of A Account Ref. | Balance as at Dec. 31, 2019 (Forecast) |
|---|---|---|
| NRP Transmission Line Revenue Requirement Deferral Account | 1508 | 6.38 |
| **Total Regulatory Accounts** | | **6.38** |

Information on the account and its balance is described in Section 2.0 of this Exhibit, with a detailed continuity schedule for the year 2019, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances presented in Exhibit H, Tab 1, Schedule 2.

Note that in this Application, NRLP is requesting recovery of the forecast 2019 NRP Transmission Line Revenue Requirement Deferral Account balance. NRLP recognized that the 2018 balance that is it seeking recovery for is unaudited, however, NRLP has requested the continuance of the account into 2020 which will allow for the true-up of any differences as explained below.

## 2. DESCRIPTION OF CURRENT REGULATORY ACCOUNTS

As presented in Exhibit H, Tab 1, Schedule 2, there is a forecast 2019 balance of $6.38 million in the NRLPDA. As such, NRLP is requesting to adjust its revenue requirement over a one-year period commencing January 1, 2020.

### 2.1 NIAGARA REEINFORCEMENT LIMITED PARTNERSHIP DEFERRAL ACCOUNT (NRLPDA)

On September 26, 2019 HONI received approval for the establishment of the NRLPDA to record the revenue requirement for the Niagara Reinforcement Project that was placed in-service on August 30, 2019. The account was approved with an effective date of September 1, 2019, and will record the revenue requirement from the time of the in-service of the assets up to the OEB-approved effective date of this Application[1].

As of December 31, 2019, the balance in the account is forecast to be $6.38 million. This application is requesting recovery of the forecast 2019 balance. This account will be reported to the OEB on a quarterly basis, consistent with the OEB's Reporting and Record Keeping Requirements.

NRLP requests the continuance of the account into 2020. This request is for 2 reasons.

1. NRLP intends to true up the balance in the NRLPDA with the actual audited balance as of the date once audited statements are available. If the actual audited balance is lower than the amount included in revenue, NRLP will record the negative difference in the account. This amount will be interest improved and refunded to ratepayers during the next rate application. If the audited balance is greater than the forecast amount, NRLP will not seek reimbursement.

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[1] NRLP is requesting that revenue from UTRs begins as of January 1, 2020. In that event, the NRLPDA would cease recording of revenue requirement as of December 31, 2019.

2. NRLP is seeking revenue beginning January 1, 2020, but acknowledges that an OEB decision on the application may not be available by that date. In that event, NRLP proposes to use the NRLPDA to record any differences between the interim revenue awarded and the actual revenue included in the final decision. Any balance will be interest improved and submitted for disposition at NRLP's next rate application.

## 3. DESCRIPTION OF NEW REGULATORY ACCOUNTS REQUESTED

### 3.1 EARNINGS SHARE MECHANISM DEFERRAL ACCOUNT

NRLP proposes a new earnings sharing mechanism ("ESM") deferral account, effective January 1, 2020, to record any material over-earnings realized during any year of the five-year term through NRLP's transmission revenue. The use of an ESM will provide protection for ratepayers if forecasts differ from actual results. The 100 basis points would satisfy the OEB-defined materiality threshold and have an impact on NRLP's operations.

The ratepayer share (50%) of the excess earnings (exceeds the regulated return by more than 100 bps) will be credited to this new deferral account. A share of excess earnings may be entered for multiple years if applicable. No reductions will be entered for years where the earnings are below the regulated return by more than 100bps.

Any balance in the account will be put forward for disposition at the time of NRLP's next rate rebasing application. A draft accounting order is provided in Appendix A to this Exhibit in support of this request.

### 3.2 TAX RATE AND RULE CHANGES VARIANCE ACCOUNT

NRLP proposes a new tax rate and rule changes variance account, effective January 1, 2020. The account shall track the revenue requirement impact of legislative or regulatory changes to tax rates or rules compared to costs approved by the OEB as part of 2020 to 2024 transmission rates, and differences that result from a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

A draft accounting order is provided in Appendix B to this Exhibit.

## 4. ACCOUNTING AND CONTROL PROCESS

The accounts noted above will be managed in a consistent manner. When applicable, they will be updated monthly and interest applied to the monthly opening principal balance in this account according to the Board-approved rate. Balances will be reported to the Board as part of the quarterly reporting process. The outstanding balances, whether in a debit or credit position, will be submitted for approval to the Board as part of a future NRLP rate application.

# Appendix A: NRLP ACCOUNTING ORDER

## <u>Transmission Accounting Order – ESM Deferral Account</u>

NRLP proposes the establishment of a new "Earnings Sharing Mechanism ("ESM") Deferral Account" to record 50% of any earnings that exceed the regulatory return on equity reflected in this Application by more than 100 basis points in any year of the five-year term through NRLP's transmission revenue. The ROE calculation will be consistent with how NRLP will calculate and submit ROE using an OEB-approved template as part of the annual RRR process.

The account will be established as Account 2435, Accrued Rate-Payer Benefit effective January 1, 2020. NRLP will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this deferral account.

| **USofA #** | **Account Description** |
|---|---|
| DR: 4395 | Rate-Payer Benefit Including Interest |
| CR: 2435 | Accrued Rate-Payer Benefit |

Initial entry to record the over-earnings realized in any year of the five-year term.

| **USofA #** | **Account Description** |
|---|---|
| DR: 4395 | Rate-Payer Benefit Including Interest |
| CR: 2435 | Accrued Rate Payer Benefit |

To record interest improvement on the principal balance of the ESM deferral account.

# Appendix B: NRLP ACCOUNTING ORDER

**Transmission Accounting Order – Tax Rate and Rule Changes Variance Account**

NRLP proposes the establishment of a new "Tax Rate and Rule Changes Variance Account" to track the revenue requirement impact of legislative or regulatory changes to tax rates or rules compared to costs approved by the OEB in NRLP's 2020 to 2024 transmission rates.

The account will be established as Account 1592, PILS and Tax Variances for 2006 and Subsequent Years effective January 1, 2020. NRLP will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

| **USofA #** | **Account Description** |
|---|---|
| DR: 1592 | PILS and Tax Variances for 2006 and Subsequent Years |
| CR: 4110 | Transmission Services Revenue |

Initial entry to record the revenue requirement impact of legislative or regulatory changes to tax rates or rules compared to costs approved by the OEB.

| **USofA #** | **Account Description** |
|---|---|
| DR: 1592 | PILS and Tax Variances for 2006 and Subsequent Years |
| CR: 6035 | Other Interest Expense |

To record interest improvement on the principal balance of the tax rate and rule changes variance account.

| Account Descriptions | Account Number | 2019 Opening Principal Amounts as of Jan-1-19 | Forecasted Transactions Debit / (Credit) during 2019 excluding interest and adjustments | Board-Approved Disposition during 2019 | Closing Principal Balances as of Dec 31-19 Adjusted for Dispositions | Opening Interest Amounts as of Jan-1-19 | Interest Disposition during 2019 - instructed by Board | Projected Interest Jan-1 to Dec-31-19 | Projected Interest Balance as at Dec 31 -19 balance adjusted for disposition during 2019 | Forecasted 2019 total balance (for evidence) |
|---|---|---|---|---|---|---|---|---|---|---|
| NRP Transmission Line Revenue Requirement Deferral Account | 1508 | - | 6,380,000 | - | 6,380,000 | - | - | 35,057 | 35,057 | 6,415,057 |
| **Total Transmission Regulatory Accounts Requesting for Disposition** | | **-** | **6,380,000** | **-** | **6,380,000** | **-** | **-** | **35,057** | **35,057** | **6,415,057** |
| **Total Transmission Regulatory Accounts** | | **-** | **6,380,000** | **-** | **6,380,000** | **-** | **-** | **35,057** | **35,057** | **6,415,057** |

# COST ALLOCATION AND RATE DESIGN

## 1. COST ALLOCATION

All assets associated with NRLP are classified as Network assets, consistent with the cost allocation methodology approved by the Board for Hydro One Networks most recently approved transmission rate application (EB-2016-0160). A listing of the NRLP assets by functional category is provided below in Table 1. Accordingly, all of the rates revenue requirement associated with NRLP's transmission assets will be allocated to the Network pool.

**Table 1 – NRLP Assets by Functional Category**

| Circuit | Section | From | To | Functional Category |
|---|---|---|---|---|
| Q26M | 4 | Allanburg West JCT | Middleport TS | Network |
| Q35M | 4 | Allanburg West JCT | St.Anns JCT | Network |
| Q35M | 5 | St.Anns JCT | Caledonia Q35M JCT | Network |
| Q35M | 6 | Caledonia Q35M JCT | Middleport TS | Network |

The NRLP Network rates revenue requirement for the purpose of setting uniform transmission rates effective for test year 2020 is $15.77 million as shown in detail in Exhibit E, Tab 1, Schedule 1. This is made up of the disposal of the NRLPDA with the forecast revenue requirement for 2019 of $6.38 million as well as the estimated 2020 base revenue requirement of $9.39 million.

## 2. CHARGE DETERMINANTS

There are no customer delivery points supplied directly from the NRLP assets, and as such the NRLP Network charge determinant for the purpose of setting Uniform Transmission Rates is zero.

# OVERVIEW OF UNIFORM TRANSMISSION

## 1. INTRODUCTION

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002, as per the OEB's Decision in RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Uniform Transmission Rates ("UTR") Schedules, which were effective on July 1, 2019, as part of the OEB's Decision and Rate Order in EB-2019-0164 issued on July 25, 2019, are filed as Exhibit I, Tab 3, Schedule 1, Attachment 1. Exhibit I, Tab 3, Schedule 1, Attachment 2 shows the revenue requirement and charge determinant details used to derive the currently approved 2019 UTRs.

Since rates are established on a uniform basis, NRLP's requested revenue requirement is a contributor to the total revenue requirement to be collected from the provincial UTR. The revenue requirement for all the other transmitters in the province approved to participate in the UTRs must be added to that of NRLP in order to calculate the total transmission revenue requirement to be collected via the UTR.[1]

The total revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement for NRLP will be allocated to the Network rate pool, as discussed in Exhibit I, Tab 1, Schedule 1. The revenue requirement by rate pool for the other transmitters is based on the proportions established by HONI Transmission's Cost Allocation process. Once the revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each pool to the

[1] The other five transmitters currently included in the UTRs are Hydro One Networks Transmission, B2M LP, Hydro One Sault Ste. Marie (formerly Great Lakes Power Transmission Inc.), Canadian Niagara Power Inc., and Five Nations Energy Inc.

total revenue for each pool. The Provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the Board for each of the transmitters participating in the UTR.

The proposed 2020 UTR schedules are provided in Exhibit I, Tab 4, Schedule 1, Attachment 1, and the revenue requirement and charge determinants details used to calculate the 2020 UTRs are provided in Exhibit I, Tab 4, Schedule 1, Attachment 2. In its 2020-2022 Transmission Custom IR Application (EB-2019-0082), Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years, such as inclusion of energy storage facilities. The "Embedded Generation" section (page 3) and Note 3 (page 5) in Exhibit I, Tab 4, Schedule 1, Attachment 1 in this application align with Hydro One's proposed changes in EB-2019-0082[2]. The proposed 2020 UTR calculation includes the proposed 2020 NRLP rates revenue requirement and the currently approved values for HONI Transmission, B2M LP, Hydro One Sault Ste. Marie, Canadian Niagara Power Inc., and Five Nations Energy Inc.

[2] See EB-2019-0082 Exhibit JT 2.34-Q18 for more information.

## 2. BILL IMPACTS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. The approach used in HONI's Transmission Rate Application (EB-2019-0082) has been adopted to determine the impact of proposed changes to transmission rates on an average customer's bill. Table 1 shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

**Table 1 - Estimated Transmission Cost as a Percentage of Total Electricity Market Costs**

| Bill Component | ¢/kWh | Source |
|---|---|---|
| Commodity | 11.49 | IESO Monthly Market Report December 2018 |
| Wholesale Market Service Charges | 0.39 | IESO Monthly Market Report December 2018 |
| Wholesale Transmission Charges | 1.08 | IESO Monthly Market Report December 2018 |
| Debt Retirement Charge | 0.18 | IESO Monthly Market Report December 2018 |
| Distribution Service Charges | 2.83 | 2018 Yearbook of Electricity Distributors |
| **Total Cost** | **15.97** | |
| *Transmission as % of Total Cost for Dx-connected customers* | *6.8%* | |
| *Transmission as % of Total Cost for Tx-connected customers* | *8.2%* | |

The NRLP 2020 rates revenue requirement represents about 0.9% of the total revenue requirement across all transmitters, which is approximated by adjusting the 2019 overall approved UTR revenue requirement to include the NRLP 2020 rates revenue requirement[3]. This percentage has been applied to NRLP's proposed changes in revenue requirement to calculate the net impact on average transmission rates for each year of the Test period. The figures from Table 1 have been applied to the proposed net impact on

[3] Exhibit E, Tab 1, Schedule 1, Table 1.

average transmission rates from 2020 to 2024 to establish the average bill impact on transmission and distribution-connected customers as shown in Table 2.

**Table 2 - Average Bill Impacts on Transmission and Distribution-Connected Customers**

| | 2019 | 2020 (Note) | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Rates Revenue Requirement ($Millions) | 0.0 | 15.77 | 9.5 | 9.7 | 9.8 | 9.9 |
| % Increase in Rates Revenue Requirement over prior year | | N/A* | -39.6% | 1.4% | 1.4% | 1.4% |
| % Impact of load forecast change | | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Net Impact on Average Transmission Rates** | | 0.95% | -0.37% | 0.01% | 0.01% | 0.01% |
| Transmission as a % of Tx-connected customer's Total Bill | | 8.2% | 8.2% | 8.2% | 8.2% | 8.2% |
| **Estimated Average Bill impact** | | 0.08% | -0.03% | 0.00% | 0.00% | 0.00% |
| Transmission as a % of Dx-connected customer's Total Bill | | 6.8% | 6.8% | 6.8% | 6.8% | 6.8% |
| **Estimated Average Bill impact** | | 0.06% | -0.03% | 0.00% | 0.00% | 0.00% |

*Note: 2020 Rates Revenue Requirement per Exhibit E, Tab 1, Schedule 1, and 2021-2024 Rates Revenue Requirement per Exhibit A, Tab 4, Schedule 1.*
**N/A as 2019 rates revenue requirement is zero.*

The total bill impact for a typical medium density residential (Hydro One R1) customer consuming 750 kWh monthly and a typical General Service Energy less than 50 kW (Hydro One GSe < 50 kW) customer consuming 2,000 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR"), as detailed in Table 3.

**Table 3 - Typical Customer Monthly Bill Impacts**

| | **Typical Medium Density (HONI R1) Residential Customer 750 kWh** | **Typical General Service Energy less than 50 kW (HONI GSe < 50kW) Customer 2,000 kWh** |
|---|---|---|
| Total Bill as of May 1, 2018[1] | $124.30 | $389.14 |
| RTSR included in R1 Customer's Bill (based on 2019 Interim UTR) | $11.94 | $25.21 |
| *Estimated 2020 Monthly RTSR[2]* | $12.00 | $25.33 |
| **2020 increase in Monthly Bill** | **$0.06** | **$0.13** |
| *2020 increase as a % of total bill* | *0.05%* | *0.03%* |
| *Estimated 2021 Monthly RTSR[2]* | $11.98 | $25.28 |
| **2021 increase in Monthly Bill** | **($0.02)** | **($0.05)** |
| *2021 increase as a % of total bill* | *-0.02%* | *-0.01%* |
| *Estimated 2022 Monthly RTSR[2]* | $11.98 | $25.29 |
| **2022 increase in Monthly Bill** | **$0.00** | **$0.00** |
| *2022 increase as a % of total bill* | *0.00%* | *0.00%* |
| *Estimated 2023 Monthly RTSR[2]* | $11.98 | $25.29 |
| **2023 increase in Monthly Bill** | **$0.00** | **$0.00** |
| *2023 increase as a % of total bill* | *0.00%* | *0.00%* |
| *Estimated 2024 Monthly RTSR[2]* | $11.98 | $25.29 |
| **2024 increase in Monthly Bill** | **$0.00** | **$0.00** |
| *2024 increase as a % of total bill* | *0.00%* | *0.00%* |

*[1]Total bill including HST, based on time-of-use commodity prices and distribution rates effective May 1, 2018 (implemented July 1, 2019) approved per Distribution Rate Order EB-2017-0049 (includes impacts of all applicable components of the Fair Hydro Plan).*

*[2]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2.*

# CURRENT ONTARIO TRANSMISSION RATE SCHEDULES

The current Uniform Transmission Rate ("UTR") Schedules were approved as part of the 2019 Decision and Rate Order dated July 25, 2019 under EB-2019-0164. This approved rate schedule, and the revenue requirement and charge determinants for all transmitters used to establish the current UTRs and revenue disbursement allocators are included in the following attachments.

**Attachment 1:** 2019 Ontario Uniform Transmission Rate Schedules
**Attachment 2:** 2019 Uniform Transmission Rates and Revenue Disbursement Allocators

Filed: 2019-10-25
EB-2018-0275
Exhibit I-03-01
Attachment 1
Page 1 of 6

# 2019 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

## EB-2019-0164

**The rate schedules contained herein shall be implemented as of July 1, 2019**

Issued: July 25, 2019
Ontario Energy Board

## TERMS AND CONDITIONS

**(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

**(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

**(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

**(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

**(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

**(F) METERING REQUIREMENTS** In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

**(G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

**(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

## RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

***APPLICABILITY:***

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

| | Monthly Rate ($ per kW) |
|---|---|
| **Network Service Rate (PTS-N):** | **3.83** |
| $ Per kW of Network Billing Demand [1,2] | |
| **Line Connection Service Rate (PTS-L):** | **0.96** |
| $ Per kW of Line Connection Billing Demand [1,3] | |
| **Transformation Connection Service Rate (PTS-T):** | **2.30** |
| $ Per kW of Transformation Connection Billing Demand [1,3,4] | |

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a “Per Transmission Delivery Point” basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

## RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

***APPLICABILITY:***

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

| | **Hourly Rate** |
|---|---|
| **Export Transmission Service Rate (ETS):** | $1.85 / MWh |

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

**2019 Uniform Transmission Rates and Revenue Disbursement Allocators**

(for Period July 1, 2019 to December 31, 2019)

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | Total |
| FNEI | $4,541,221 | $1,134,788 | $2,312,083 | $7,988,092 |
| CNPI | $2,641,928 | $660,181 | $1,345,091 | $4,647,201 |
| H1N SSM | $21,608,304 | $5,399,616 | $11,001,490 | $38,009,410 |
| H1N | $891,888,531 | $222,870,611 | $454,089,436 | $1,568,848,577 |
| B2MLP | $32,789,151 | $0 | $0 | $32,789,151 |
| All Transmitters | $953,469,135 | $230,065,197 | $468,748,100 | $1,652,282,431 |

| Transmitter | Total Annual Charge Determinants (MW)** | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| FNEI | 230.410 | 248.860 | 73.040 | |
| CNPI | 522.894 | 549.258 | 549.258 | |
| HIN SSM | 3,498.236 | 2,734.624 | 635.252 | |
| H1N | 244,924.157 | 236,948.242 | 202,510.123 | |
| B2MLP | 0.000 | 0.000 | 0.000 | |
| All Transmitters | 249,175.697 | 240,480.984 | 203,767.673 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| Uniform Transmission Rates ($/kW-Month) | **3.83** | **0.96** | **2.30** | |
| | | | | |
| **FNEI** Allocation Factor | **0.00476** | **0.00493** | **0.00493** | |
| **CNPI** Allocation Factor | **0.00277** | **0.00287** | **0.00287** | |
| **H1N SSM** Allocation Factor | **0.02266** | **0.02347** | **0.02347** | |
| **H1N** Allocation Factor | **0.93542** | **0.96873** | **0.96873** | |
| **B2MLP** Allocation Factor | **0.03439** | **0.00000** | **0.00000** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

** The sum of 12 monthly charge determinants for the year.

*Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.*

*Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.*

*Note 3: H1N SSM 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218 dated July 18, 2019.*

*Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated June 13, 2019.*

*Note 5: B2M LP 2018 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.*

*Note 6: Calculated data in shaded cells.*

# PROPOSED ONTARIO TRANSMISSION RATE SCHEDULES

The proposed Uniform Transmission Rate ("UTR") Schedule and the revenue requirement and charge determinants for all transmitters used to establish the proposed UTRs and revenue disbursement allocators are included in the following attachments.

**Attachment 1:** Proposed 2020 Ontario Uniform Transmission Rate Schedules
**Attachment 2:** Proposed 2020 Uniform Transmission Rates and Revenue Disbursement Allocators

Filed: 2019-10-25
EB-2018-0275
Exhibit I-04-01
Attachment 1
Page 1 of 6

# 2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

## EB-2018-0275

**The rate schedules contained herein shall be effective January 1, 2020**

Issued: Month, Year
Ontario Energy Board

## TERMS AND CONDITIONS

**(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

**(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

**(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

**(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

**(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

**(F) METERING REQUIREMENTS** In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

**(G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generator unit or energy storage facility are obtained after October 30, 1998; and (b) the generator unit nameplate rating is 2 MW or higher for renewable generation and 1 MW or higher for non- renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage; and (c) the Transmission Delivery Point through which the generator or energy storage facility is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments or expansions approved after October 30, 1998, to a generator or generation facility that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental generator nameplate capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for expansion of energy storage facilities. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

**(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

## RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

***APPLICABILITY:***

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

| | Monthly Rate ($ per kW) |
|---|---|
| **Network Service Rate (PTS-N):** | **3.89** |
| $ Per kW of Network Billing Demand [1,2] | |
| **Line Connection Service Rate (PTS-L):** | **0.96** |
| $ Per kW of Line Connection Billing Demand [1,3] | |
| **Transformation Connection Service Rate (PTS-T):** | **2.30** |
| $ Per kW of Transformation Connection Billing Demand [1,3,4] | |

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit or energy storage facility for which the required government approvals are obtained after October 30, 1998 and which have installed nameplate capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage, or the demand supplied by the incremental capacity associated with a refurbishment or expansion approved after October 30, 1998, to a generator or generation facility that existed on or prior to October 30, 1998. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

## RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

***APPLICABILITY:***

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

| | Hourly Rate |
|---|---|
| **Export Transmission Service Rate (ETS):** | $1.85 / MWh |

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

**NRLP**

Projected Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2020 to December 31, 2020)

| Transmitter | Revenue Requirement ($) | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | Total |
| FNEI | $4,541,221 | $1,134,788 | $2,312,083 | $7,988,092 |
| CNPI | $2,641,928 | $660,181 | $1,345,091 | $4,647,201 |
| H1N SSM | $21,608,304 | $5,399,616 | $11,001,490 | $38,009,410 |
| H1N | $891,888,531 | $222,870,611 | $454,089,436 | $1,568,848,577 |
| B2MLP | $32,789,151 | $0 | $0 | $32,789,151 |
| NRLP | $15,774,305 | $0 | $0 | $15,774,305 |
| All Transmitters | $969,243,439 | $230,065,197 | $468,748,100 | $1,668,056,736 |

| Transmitter | Total Annual Charge Determinants (MW)** | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| FNEI | 230.410 | 248.860 | 73.040 | |
| CNPI | 522.894 | 549.258 | 549.258 | |
| H1N SSM | 3,498.236 | 2,734.624 | 635.252 | |
| H1N | 244,924.157 | 236,948.242 | 202,510.123 | |
| B2MLP | 0.000 | 0.000 | 0.000 | |
| NRLP | 0.000 | 0.000 | 0.000 | |
| All Transmitters | 249,175.697 | 240,480.984 | 203,767.673 | |

| Transmitter | Uniform Rates and Revenue Allocators | | | |
|---|---|---|---|---|
| | Network | Line Connection | Transformation Connection | |
| Uniform Transmission Rates ($/kW-Month) | **3.89** | **0.96** | **2.30** | |
| | | | | |
| **FNEI** Allocation Factor | **0.00469** | **0.00493** | **0.00493** | |
| **CNPI** Allocation Factor | **0.00273** | **0.00287** | **0.00287** | |
| **H1N SSM** Allocation Factor | **0.02229** | **0.02347** | **0.02347** | |
| **H1N** Allocation Factor | **0.92019** | **0.96873** | **0.96873** | |
| **B2MLP** Allocation Factor | **0.03383** | **0.00000** | **0.00000** | |
| **NRLP** Allocation Factor | **0.01627** | **0.00000** | **0.00000** | |
| Total of Allocation Factors | 1.00000 | 1.00000 | 1.00000 | |

** The sum of 12 monthly charge determinants for the year.

*Note 1: FNEI Rates Revenue Requirement and Charge Determinants Order EB-2016-0231 dated January 18, 2018.*
*Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.*
*Note 3: H1N SSM 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218 dated July 18, 2019*
*Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated June 13, 2019.*
*Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.*
*Note 6: NRLP proposed 2020 Revenue Requirement per Exhibit E, Tab 1, Schedule 1.*
*Note 7: Calculated data in shaded cells.*