**Hydro One Networks Inc.**
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5393
Fax: (416) 345-6833
Joanne.Richardson@HydroOne.com

**Joanne Richardson**
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

June 14, 2019

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

Dear Ms. Walli:

**EB-2018-0270 - Hydro One Networks Inc. MAAD S86 to Purchase all of the issued and outstanding shares of Orillia Power Distribution Corporation – Interrogatory Responses**

Please find attached Hydro One Networks Inc.'s (Hydro One) responses to interrogatories received in the above-noted proceeding as part of Procedural Order No.5 dated May 9, 2019. The interrogatory responses have been organized by party as indicated below:

| | |
|---|---|
| Tab 1 | OEB Staff |
| Tab 2 | School Energy Cooalition (SEC) |
| Tab 3 | Energy Probe |
| Tab 4 | Powers Workers Union (PWU) |
| Tab 5 | Vulnerable Energy Consumers Cooalition (VECC) |
| Tab 6 | Consumers Council of Canada (CCC) |

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

cc. Parties to EB-2018-0270 (electronic only)

# OEB STAFF INTERROGATORY # 1

**Reference:**
Exhibit A-1-1

**Interrogatory:**
**Preamble:**
At Exhibit A-1-1 p. 3, the Applicants state:

> On August 15, 2016, the City and Orillia Power Corporation (the "Vendor") and HOI (the "Purchaser") entered into a Share Purchase Agreement (the "Agreement"), the effect of which is that the Vendor and the City have agreed to sell, and the Purchaser has agreed to purchase, all of the issued and outstanding shares of OPDC. The purchase price is $41.3 million, comprising a cash payment of approximately $26.4 million for the shares and the assumption of OPDC's short- and long-term debt (including regulatory deferral account balances) of approximately $14.9 million.

***-and-***

At Exhibit A-1-1 p. 4, the Applicants state:

> The purchase price is subject to adjustment, within 90 days following closing, for working capital, net fixed assets, regulatory accounts and long term debt, as defined in the Agreement.

**Questions:**

a) If applicable, what is the expiration date of the Share Purchase Agreement?

b) Acknowledging that the purchase price is subject to adjustment, however, in consideration of the principle of transparency; the valuation upon which the purchase price was based is now approximately 2.5 years old:

   i. On what basis did the Applicants determine it was not necessary to update the valuation before filing this second application requesting OEB approval of the proposed transaction?

ii. What changes to the underlying inputs that informed the valuation – including, but not limited to, short- and long-term debt and net assets, have occurred since completion of the original valuation?

**Response:**

a) The Share Purchase Agreement does not have an expiry date.

b) The Applicants made any updates, as needed, to the MAAD application that would or could impact ratepayers. This included updating the OM&A and Capital Forecasts and updating the ESM model from the evidence provided in EB-2016-0276, including its economic parameters. The Applicants also provided additional evidence on future cost structures (Exhibit A, Tab 4, Schedule 1) and new Supplemental Evidence to further explain Hydro One's proposed cost allocation and rate design for OPDC customers in Year 11 and onwards.

Any other updates to the purchase price, including any premium above the historic value of the assets involved are, per the OEB's January 19, 2016 *Handbook to Electricity Distributor and Transmitter Consolidations*, only reviewed by the Board if they impact the financial viability of Hydro One.

> "In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed." [1]

The premium that Hydro One has paid and the amount that the City of Orillia has agreed to sell the shares of OPDC to Hydro One for, will not find their way into future rates. Hydro One reconsidered the valuation of OPDC and determined that the purchase price was not set at a level that would create a financial burden on Hydro One.

[1] Handbook to Electricity Distributor and Transmitter Consolidations – page 8.

# OEB STAFF INTERROGATORY # 2

**Reference:**

Exhibit A-1-1

**Interrogatory:**

**Preamble:**

At Exhibit A-1-1 p. 4, the Applicants state:

> The Purchaser or its affiliates shall offer all active employees of OPDC continued employment in the City of Orillia for a period of at least one year;

***-and-***

At Exhibit A-2-1 p. 8, the Applicants state:

> As part of the proposed consolidation, Hydro One will retain local knowledge from existing OPDC staff. This local knowledge, in coordination with Hydro One's regional operations and staff, will allow Hydro One to maintain or improve reliability.

**Questions:**

a) Please clarify how, from an employment standpoint, current employees of OPDC may be impacted one year following the proposed transaction?

   i. If applicable, how many, and what type of employees will be impacted?

b) How will Hydro One ensure that the local knowledge necessary to ensure reliability levels are maintained/improved if only 9 of the current 15 OPDC direct staff (i.e., direct staff as defined by the Applicants at Exhibit A-2-1 p. 12) will be required following Year 1 of the proposed transaction?

   i. Please discuss how the loss of 6 direct staff, equivalent to 40% of OPDC's current complement, will not result in a disruption to current OPDC service and reliability performance.

In the event that a major outage occurs in the current OPDC and surrounding Hydro One service areas at the same time, to what degree will the loss of the 6 OPDC direct staff impact service restoration times for both current OPDC and Hydro One customers?

**Response:**

a) At this point in time, there are no specific plans for staff beyond their initial mapping. Beyond one year following the proposed transaction, employees will be treated in accordance with the applicable collective agreements between Hydro One and their respective union partners and/or Hydro One's processes.

b) With regards to the reduction of 6 positions, presently OPDC Lines' staff perform work activity that Hydro One does not consider to be "Powerline Maintainer" core work. These activities include line vegetation management. Hydro One has a Utility Arborist division that currently performs this work activity. Further, Hydro has a designated work force responsible for large capital and maintenance programs/projects. There are significant efficiencies as well as reliability gains by having a workforce that can be mobilized to construct a project start to finish, complete maintenance programs uninterrupted and restore power during significant weather events. Under the current OPDC organization structure, these types of crew activities would be interrupted whenever Customer Demand activity requires the resources. In the event of a major outage occurring in the current OPDC and surrounding Hydro One service areas at the same time; Hydro One can efficiently and quickly mobilize additional resources (staff and equipment) from across not only adjoining Hydro One service territories but from across the Province.

# OEB STAFF INTERROGATORY # 3

**Reference:**
Exhibit A-2-1

**Interrogatory:**
**Preamble:**
The following table is an extract from Exhibit A-2-1 p. 2 of the application:

**Table 1: Projected Cost Savings - $M**

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A** | | | | | | | | | | |
| Status Quo Forecast | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 | 6.6 |
| Hydro One Forecast | 4.1 | 2.0 | 2.1 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 |
| Projected Savings | **1.4** | **3.7** | **3.7** | **4.2** | **4.3** | **4.4** | **4.4** | **4.6** | **4.7** | **4.7** |
| **Capital** | | | | | | | | | | |
| Status Quo Forecast | 3.2 | 4.3 | 1.5 | 1.8 | 2.8 | 2.8 | 2.9 | 3.0 | 11.1 | 3.2 |
| Hydro One Forecast | 3.4 | 2.4 | 2.4 | 2.5 | 2.6 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 |
| Projected Savings | **(0.2)** | **1.9** | **(0.9)** | **(0.7)** | **0.2** | **0.0** | **0.1** | **0.1** | **8.2** | **0.2** |

**Questions:**

a) The table above demonstrates a forecast capital savings of $8.2 million in Year 9 following the acquisition. Please describe the capital expense(s) offset by the acquisition that result(s) in the $8.2 million cost savings.

   i. Please explain how the acquisition can deliver this capital cost reduction in Year 9.

b) The application states that efficiencies gained through the acquisition will reduce OPDC's current OM&A costs by approximately 70% from the status quo scenario by Year 10. Please provide an accounting of each OM&A cost category reduction and its contribution to this forecast 70% reduction.

**Response:**

a) A new OPDC operations centre, representing an $8 million capital expenditure, is incorporated at Year 9 of Status Quo Forecast.

OPDC's original building was constructed in the 1950's which means the facility is close to 70 years old. Additional office space was added on to the facility in 1973. In 2013, a detailed building condition assessment was completed. Based on the results of the condition assessment and considering various items including projected repair and refurbishment costs and the needs of the Company going forward, in 2014, OPDC began the process of investigating new building options. An RFP for architectural design services was issued in 2014 and an architect was selected. OPDC staff worked with the architect throughout late 2014 and into 2015 to design an appropriate facility to meet the Company's needs. This process was proceeding well, with expectations that construction would begin in 2015. However, once it was known that Hydro One was looking to acquire OPDC, the design and planning process was halted. In light of the ongoing regulatory process related to the Hydro One acquisition of OPDC, no further work has been carried out on the planning for a new facility.

In the event that the MAAD application does not achieve regulatory approval, OPDC would need to resume plans to construct a new facility as the current building is not suitable for the long-term needs of the organization.

By comparison, the Hydro One Forecast represents integrated operation of the former OPDC service territory and makes use of Hydro One facilities already necessary to serve current Hydro One customers. Thereby, Hydro One's acquisition of the former OPDC service territory avoids the status quo requirement for a new dedicated OPDC service centre which represents an $8M capital expenditure savings in Year 9.

b) The following table provides anticipated on-going OM&A cost reductions attributed to major business areas. The higher end of the range aligns with the Year 10 savings vs the Status Quo.

**Table 1**

| **Savings / Synergy Category** | **Annual Range** ($ million) |
|---|---|
| Administration | |
| Management / Corporate Governance | 0.8 - 0.9 |
| Financial / Regulatory | 0.4 - 0.5 |
| Other | 0.1 - 0.7 |
| | |
| Back Office | |
| Customer Service | 0.6 - 0.7 |
| Information Technology / Other | 0.6 - 0.7 |
| | |
| Distribution Operations | 1.2 - 1.3 |
| | |
| **Total OM&A** | **3.6 - 4.7** |

# OEB STAFF INTERROGATORY # 4

**Reference:**

Exhibit A-2-1

**Interrogatory:**

**Preamble:**

At Exhibit A-2-1 p. 3, the Applicants state:

> Hydro One's 2017 OM&A cost to serve customers in its high density residential rate class (UR) is $179/customer, compared to OPDC's cost of $352/customer.

**Questions:**

a) Please confirm if Hydro One's 2017 OM&A cost to serve of $179/customer includes Hydro One Shared Costs as described at Exhibit A-4-1 p. 6 of the application.

   i. If applicable, please provide an estimation of Hydro One's 2017 OM&A cost to serve its high density residential rate class inclusive of Shared Costs.

b) Please provide Hydro One's most recent per customer OM&A cost to serve its high density residential rate class.

   i. Please demonstrate the OM&A cost to serve with and without Shared Costs.

c) Please provide OPDC's most recent per customer OM&A cost to serve.

d) Please provide a forecast of OM&A costs to serve, inclusive of Shared Costs, for current OPDC customers following the rebasing deferral period.

   i. Please fully describe the methodology used by the Applicants to determine and assign Shared Costs to current OPDC customers following the rebasing deferral period.

**Response:**

a) Confirmed.

b) The Table below provides the allocated OM&A costs attributed to Hydro One's urban density residential rate class, consistent with the values provided in EB-2017-0049, Draft Rate Order Exhibit 3.1 (O1 Sheet of the Cost Allocation Model (CAM)).

| **Rate Class** | **"Direct" OM&A Costs** | **"Shared" OM&A Costs** | **Total Allocated OM&A Costs** |
|---|---|---|---|
| HONI UR | $ 12,542,544 | $ 27,352,208 | $ 39,894,752 |

The "Direct" OM&A shown in the Table are the amounts identified as "Distribution (di)" costs in the 'O1' sheet of the CAM. These values include the allocated OM&A costs associated with distribution fixed assets, which includes the cost of certain Shared Costs, as defined in this application (e.g. OM&A associated with upstream and shared distribution facilities). The "Shared" OM&A costs shown in the table above are the amounts identified as "Customer Related Costs (cu)" and "General and Administration (ad)"in the 'O1' sheet of the CAM.

c) The most recent data for OPDC results in an OM&A per customer of $359 as documented in Table 1 below.

**Table 1**
**OM&A Expenses**

| | |
|---|---|
| Operating | $1,105,352 |
| Maintenance | 1,198,663 |
| Administrative | 2,752,028 |
| **Total OM&A** | **$5,056,043** |
| # of Customers | 14,091 |
| OM&A/Customer | $359 |

d) The Table below provides the allocated OM&A costs attributed to OPDC's customers, consistent with the values provided in Exhibit I, Tab1, Schedule 9 Attachment 3 (O1 Sheet of the Cost Allocation Model (CAM)).

| | Forecast OMA Allocated to OPDC Customers* (2030) |
|---|---|
| **"Direct" OM&A Costs** | $1,403,555 |
| **"Shared" OM&A Costs** | $2,370,346 |
| **Total Allocated OM&A Costs** | $3,773,901 |

**OPDC Customers include AUR, AUGe, AUGd and Combined Classes (i.e. St Lgt, Sent Lgt and USL)*

The "Direct" OM&A shown in the Table are the amounts identified as "Distribution (di)" costs in the 'O1' sheet of the CAM. These values include the allocated OM&A costs associated with distribution fixed assets, which includes the cost of local fixed assets, as well as certain Shared Costs (e.g. OM&A associated with upstream and shared distribution facilities). The "Shared" OM&A costs shown in the table above are the amounts identified as "Customer Related Costs (cu)" and "General and Administration (ad)"in the 'O1' sheet of the CAM, and include some costs that are also part of the Residual Cost.

i) The allocation of costs, including Shared costs, to OPDC customers is described in Exhibit I, Tab 1, Schedule 9 Part b).

# OEB STAFF INTERROGATORY # 5

**Reference:**
Exhibit A-2-1

**Interrogatory:**
**Preamble:**
At Exhibit A-2-1 p. 7, the Applicants state:

> Beginning in year six through to year ten, rates for the former customers of OPDC will be set using the Price Cap adjustment mechanism, as outlined in the Board's Report: "Rate Making Associated with Distributor Consolidation" issued March 26, 2015 ("Amended Report"). At the commencement of year six, Hydro One will apply the OEB's Price Cap Index formula utilizing the former OPDC's efficiency cohort factor (0.3%). This will be anchored to then current OPDC Base Distribution Delivery Rates, and applied annually.

**Questions:**

a) The Applicants propose that rates for former customers of OPDC will be set in accordance with the Price Cap adjustment mechanism during Years 6 to 10 of the rebasing deferral period. OPDC's current rates have been set in accordance with the Annual IR Index option.

   Table 1, on page 15, of the OEB issued *Handbook to Electricity Distributor and Transmitter Consolidations* prescribes that a distributor whose rates are set in accordance with the Annual IR Index must continue on the Annual IR Index method until the end of the rebasing deferral period.

   Do the Applicants accept that, if the acquisition is approved, the rates of former customers of OPDC will be set in accordance with the Annual IR Index option?

b) If applicable, please describe how projected cost efficiencies and/or customer bill impacts demonstrated in the application are impacted by the need to set rates in accordance with the Annual IR Index option as opposed to using the Price Cap adjustment mechanism.

**Response:**

a) The basis for the question is OEB Staff's statement that "OPDC's current rates have been set in accordance with the Annual IR Index option". However, this statement is not correct. As is evident from OPDC's application for 2019 distribution rates and from the OEB's Decision and Rate Order on that application, OPDC's current rates have been set in accordance with the Price Cap IR option.

OPDC filed its application in EB-2018-0061 on November 5, 2018 seeking approval for 2019 rates. As stated on p. 2 of that application, "Orillia Power has prepared this Application under the Renewed Regulatory Framework for Electricity Distributors using Price Cap IR methodology . . ."

The OEB issued its Decision and Rate Order on OPDC's 2019 rate application on March 28, 2019, for rates and charges to be effective May 1, 2019. Based on the following, it is clear from the Decision that OPDC's current rates are based on the Price Cap IR methodology:

- On p. 1 of the Decision, the OEB states "Orillia Power's application is based on a Price Cap Incentive Rate-setting option (Price Cap IR) with a five-year term . . . As a result [of Hydro One's pending MAADs application in the present proceeding], Orillia Power did not apply for the price cap (inflation rate less productivity factor) adjustment in the 2019 rate year pending the outcome of the MAADs application."

- On p. 3 of the Decision, the OEB states: "Under the Price Cap IR option, Orillia Power would be eligible to increase its distribution rates by using the OEB-approved inflation minus X-factor formula applicable to Price Cap IR applications. However, Orillia Power did not apply for this adjustment for the 2019 rate year due to the MAADs application before the OEB."

- There are no references whatsoever in the Decision to the Annual IR Index methodology.

# OEB STAFF INTERROGATORY # 6

**Reference:**
Exhibit A-5-1

**Interrogatory:**
**Preamble:**
At Exhibit A-5-1 pp. 1-2, the Applicants state:

> Hydro One's purchase of OPDC will result in over $6.5 million of savings in Year 11 (i.e., the first rebasing year), as shown in Table 1 below.

**Table 1: Savings Resulting from Hydro One's Acquisition of OPDC ($M)**

| | | |
|---|---|---|
| OPDC Status Quo Total Cost to Serve | $14.4 | *Ex. A, Tab 4, Schedule 1 – Table 4* |
| Total Residual Cost to Serve | 7.9 | *Ex. A, Tab 4, Schedule 1 – Table 4* |
| **Ratepayer Savings (Year 11)** | **$6.5** | |

**Questions:**
a) Please confirm that the $6.5 million savings reported in Table 1 does not reflect OPDC customers' apportionment of Hydro One Shared Costs.

b) For how many years post-Year 11 are the ratepayer savings demonstrated in Table 1 expected to accrue?

   i. Please provide the estimated savings for each of these years.

**Response:**
a) Confirmed.

b) The $6.5 million savings are expected to accrue on an ongoing basis post-Year 11.

# OEB STAFF INTERROGATORY # 7

**Reference:**
Exhibit A-5-1

**Interrogatory:**
**Preamble:**
At Exhibit A-5-1 p. 2, the Applicants state:

> In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of OPDC, and commits to tracking the *actual* ***incremental OM&A and capital costs*** to serve OPDC customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve OPDC customers with that forecast in this application. The actual incremental OM&A and capital costs to serve OPDC customers will be reflected in Hydro One's revenue requirement upon rebasing of rates at the end of the ten year deferral period. **[*Emphasis added*]**

**Questions:**

a) Please fully explain what is meant by "incremental OM&A and capital costs" as referenced by the Applicants at Exhibit A-5-1 p. 2. To clarify, is it the Applicants' intention to only track the incremental costs (or marginal costs) incurred by Hydro One to serve the current OPDC service territory following the proposed acquisition?

   By way of example, if Hydro One's staffing levels for certain functions, prior to the acquisition, are adequate enough to absorb the OPDC service territory without the need for added staff, would the incremental costs for that function be considered nil? What methods would Hydro One use to identify those costs that are incremental to OPDC versus those that are not?

b) Please confirm if the tracking of OPDC's incremental OM&A and capital costs will include the tracking of OPDC's Shared Costs.

   i. If Shared Costs will not be tracked, please discuss why the tracking of these costs is not required.

c) If applicable, please discuss why only incremental OM&A and capital costs will be tracked and not the total costs to serve OPDC customers until the end of the ten year deferral period.

d) At page 159 of the OEB's Decision and Order on Hydro One's Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022[1], the OEB stated:

> In approving the acquisition of Norfolk, Haldimand and Woodstock,[2] the OEB directed Hydro One to maintain records of the cost to serve these utilities in order to inform the rate-setting process at the completion of the respective deferral periods. Hydro One has not maintained these records.

Please articulate why and how the Applicants' decision to track only incremental OM&A and capital costs aligns with the expectations established by the OEB through the aforementioned Decision and Order.

**Response:**

a) Incremental OM&A and capital costs means the additional costs that Hydro One will incur as a result of the acquisition of OPDC after anticipated synergies and efficiency gains have been reflected. If OPDC was not acquired by Hydro One, these "incremental costs" would not be incurred by Hydro One and therefore would not be included in Hydro One's revenue requirement, as they are not needed to service Hydro One's legacy customers.

   Hydro One has committed to track both the incremental OM&A and capital costs to serve OPDC up until the time of the next rebasing. In the Supplemental Evidence, Hydro One has also agreed to continue to track capital costs to serve OPDC beyond the deferral period, to inform future rate-setting applications.

---

[1] EB-2017-0049
[2] EB-2013-0196/EB-2013-0187/EB-2013-0198 (Norfolk), EB-2014-0244 (Haldimand), and EB-2014-0213 (Woodstock).

The example provided by Board Staff in this interrogatory outlines some of the benefits that will be achieved by this acquisition through the elimination of redundancies and inefficiencies. These align with the OEB's intended efficiencies to be gained through consolidation. Yes, Hydro One will be able absorb certain activities and functions currently required by OPDC into its current staffing levels (e.g. preparation of financial statement, tax returns, human resources support, etc.) without incurring any additional costs. As there are no incremental costs resulting from these activities, the incremental cost would be nil.

During the ten year rebasing deferral period Hydro One will utilize its financial management and reporting system, the same system it uses for all Hydro One's financial business activities, to track incremental capital and OM&A costs to serve OPDC's customers. Hydro One's financial system will enable the reporting of these capital and OM&A expenditures over this ten year period by setting up a specific OPDC service territory cost centre. Any specific incremental cost expenditures made in OPDC's service territory during that period will be recorded and tracked in that OPDC cost centre.

b) Hydro One will track all incremental costs, which include any incremental costs that may also be categorized as shared costs. For instance, Hydro One has defined Shared Cost to include customer services, however some customer service activities, such as generating customer's bills will incur incremental costs to serve OPDC's customers. These incremental activities will be tracked separately. Hydro One's evidence is that shared costs that will be allocated through the cost allocation process will not be tracked.

Hydro One in both its Distribution and Transmission rate cases provides evidence and justification for all of its costs including its shared costs forecast captured at a corporate level. Hydro One is unable to track actual "shared costs" for any of its customer groups. These costs are not directly charged to any of Hydro One rates classes and are therefore cannot be tracked by customer group. For instance, Hydro One's Finance department's costs (which would be captured in "shared costs") are not forecast or tracked between Hydro One's Rural, UR, GSd or Acquired Utility rate classes.

Total Shared costs, including any incremental costs that may also be categorized as shared costs, will be allocated to OPDC customers based on the Board's cost allocation methodology. This is discussed at Exhibit A, Tab 4, Schedule 1.

c) All incremental costs incurred to serve OPDC customers will be tracked. See part b) above, which explains that costs which are shared amongst customer groups are not tracked on an individual customer group basis.

d) Hydro One is of the view that it has complied with the OEB direction in each of the previous MAAD decisions. In the previous MAAD applications Hydro One forecast the incremental costs to serve each utility, and has reported on those costs.

Hydro One has no means of allocating Shared Costs to OPDC customers in the deferral period. Currently, and during the deferral period, Hydro One's Shared Costs are 100% allocated to its existing legacy customers. The only time that Hydro One would calculate how much of its Shared Costs should be collected from OPDC customers is at the time of integration of OPDC customers into Hydro One's rate structures – in year 11.

# OEB STAFF INTERROGATORY # 8

**Reference:**
Exhibit A-5-1
Appendix A
Exhibit A-4-1
Decision and Order on EB-2017-0049

**Interrogatory:**
**Preamble:**
At Exhibit A-5-1 p. 4, the Applicants state:

> Hydro One believes that the best way to ensure that OPDC customers are charged only their costs to serve is to introduce new rate classes for them.

***-and-***

**Preamble:**
At page 6 of Appendix A (the Navigant Report), Navigant states:

> To distinguish customers in the acquired utility service territory from legacy customers, Hydro One proposed to create unique customer classes for customers from the acquired utility…To the extent that the cost to serve the acquired utility customer classes is different from the cost to serve Hydro One's legacy customer classes, this is a valid justification for creating unique classes for customers from the acquired utility.

***-and-***

**Preamble:**
At Exhibit A-4-1 p. 12, the Applicants state:

> With respect to former OPDC customers, Hydro One anticipates transitioning those customers to one of its proposed new Acquired Rate Classes or to a new rate class to be proposed after the deferred rebasing period has elapsed.

***-and-***

**Preamble:**

At pp. 159-165 of the Decision and Order on EB-2017-0049, the OEB states, among other things:

> The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.
>
> 1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement.

**Questions:**

a) The Applicants' statements at Exhibit A-5-1 p. 4 and at Exhibit A-4-1 p. 12 (as referenced in the preamble above) appear to be inconsistent. Please clarify the Applicants' intent as it relates to post rebasing deferral period rate setting. That is, with respect to current OPDC customers, will an attempt be made to transition these customers into an existing Acquired Rate Class or is it the Applicants' intention to introduce new rate classes?

b) If the Applicants' intention is to create new OPDC-specific rate classes, please provide a description of each new rate class the Applicants anticipate creating.

   i. For what time period following the acquisition do the Applicants anticipate the acquired rate classes being in effect? That is, when will rate harmonization take place? Alternatively, is it the expectation of the Applicants that these new rate classes will continue in perpetuity? Please justify the planned approach to future rate setting.

c) Please describe the assessment used by the Applicants to determine that, based on its unique characteristics, it is warranted that new rate classes be created for the current OPDC service territory.

i. Based on the Applicants' response to part c), please comment on the reasonableness of the OM&A cost to serve comparison referred to by OEB staff in OEB Staff-4 above.

d) Please provide the results of the assessment used by the Applicants to determine that new rate classes for OPDC are warranted. When responding, please clearly identify the sufficient differences that exist between the current OPDC service territory and other Hydro One service areas that justify the new rate classes.

**<u>Response:</u>**

a) Hydro One would transition OPDC customers to acquired rate classes that may exist at the time of rebasing provided that the acquired classes and OPDC classes have a reasonably similar cost to serve and doing so does not result in significant rate impacts to OPDC customers. In the alternative, Hydro One would propose new acquired rate classes applicable to OPDC customers after the deferred rebasing period has elapsed.

b) If necessary, Hydro One anticipates including OPDC customers in the following new acquired rate classes:
   - Acquired Residential, which will include all customers currently in the OPDC residential class
   - Acquired General Service < 50, which will include all customers currently in the OPDC GS <50 kW class.
   - Acquired General Service >50, which will include all customers currently in the OPDC GS 50 to 4,999 kW class.
   
   i. These rate classes would come into effect when the deferred rebasing period ends (i.e. for year 11), subject to Board approval, and are anticipated to be ongoing. Hydro One believes that creating new rate classes for the OPDC service territory is necessary to ensure that the rates charged to OPDC customers will appropriately reflect their cost-to-serve.

c) The cost of fixed assets associated with serving OPDC customers is unique to OPDC's service territory (e.g. size, geography, system characteristics, customer density, historical capital costs). Based on the experience with the allocation of costs using the Board's cost allocation model, it is known that the allocation of costs per the methodology underlying the Board's cost allocation model, which allocates Hydro One's average costs across its entire service territory, would result in an over-allocation of the fixed assets known to be required to serve customers in the OPDC service territory. The over-allocation of assets required to serve OPDC would result in an over-allocation of costs and the setting of rates that do not accurately reflect the cost to serve customers located in the OPDC service territory.

i) The comparison referred to by OEB staff, ignores the Footnote 3 of Exhibit A, Tab 2, Schedule 1, page 3, which indicated that the residential OPDC OM&A cost/customers is $208. This is a reasonable comparison of each utility's OM&A cost of serving the referenced rate classes that reflects the best available information at the time that the MAAD application was prepared.

d) See response to b).

# OEB STAFF INTERROGATORY # 9

**Reference:**
Exhibit A-4-1
Exhibit A-5-1
Appendix A
*Report of the Board on Application of Cost Allocation for Electricity Distributors*

**Interrogatory:**
**Preamble:**
At Exhibit A-4-1 p. 8, the Applicants state:

> Hydro One proposes within the harmonization and rebasing application following the deferral period, that it would ensure that the total cost, including a portion of Hydro One's Shared Costs, to be collected from the former OPDC customers would be between, (a) the Residual Cost to Serve scenario plus [Low Voltage] charges (totaling $7.9M); and (b) the Year 11 revenue requirement under the OPDC Status Quo scenario plus Year 11 [Low Voltage] charges (totaling $14.4M).

***-and-***

**Preamble:**
At Exhibit A-4-1 p. 6, the Applicants state:

> If the transaction is approved, the underlying cost structures for serving the former OPDC customers will be reduced by an estimated annual amount of $7.5M to a revenue requirement of $6.9M[1] under the Residual Cost to Serve scenario. The $6.9M Residual revenue requirement does not reflect OPDC customers paying their full share of the costs for services that Hydro One would be providing to OPDC customers. Hydro One considers the costs of the functions,

[1] The Residual Cost to Serve of $6.9 million does not include the Applicants' cost estimate of Low Voltage charges to former OPDC customers.

> resources and assets used to provide such services to be its "Shared Costs". More particularly, Hydro One's Shared Costs reflect, (i) shared facilities used to provide operations and maintenance services (i.e. service centres and maintenance yards), billing and IT system costs, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer services and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former OPDC customers (i.e. costs formerly captured under [Low Voltage] charges).

***-and-***

**Preamble:**

At Exhibit A-5-1 p. 5, the Applicants state:

> In order to ensure the equitable treatment of both legacy and acquired customers, Hydro One proposes to use the principles underlying the OEB's cost allocation model to determine the cost allocation to all rate classes. To the extent necessary, the OEB's cost allocation model will be adjusted to achieve the following objectives:
>
> 1. Ensure that costs allocated to the OPDC rate classes reflect the fixed assets specifically used in OPDC's service area.
>
> 2. Ensure that the OPDC rate classes are appropriately allocated Shared Costs, which includes a share of upstream distribution assets required to provide service to OPDC's service area.
>
> Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC is not acquired.

***-and-***

**Preamble:**

At pp.1-2 of Appendix A (the Navigant Report), Navigant states:

> The proposed approach to cost allocation and rate design described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence incorporates changes relative to the approach outlined in the Distribution Rate Cost Allocation Model. However, several elements are the same, and the Distribution Rate Cost Allocation Model provided Navigant with a worked, numerical, example of the approach upon which to perform a detailed review.

***-and-***

**Preamble:**

At p. 7 of the OEB's November 28, 2007 *Report of the Board on Application of Cost Allocation for Electricity Distributors*, the OEB states:

> Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one.

**Questions:**

The Applicants' evidence specifies that the Total Residual Cost to Serve does not include Shared Costs. Further, the Applicants' evidence highlights that the portion of Hydro One's Shared Costs to be collected from current OPDC customers following harmonization will be no greater than approximately $6.5 million. The $6.5 million represents the monetary value of the Applicants' estimated efficiency gains resulting from the acquisition. The Applicants also state that they will "use the principles underlying the OEB's cost allocation model" during future rate harmonization processes. The benefit of this approach, as stated by the Applicants, is that it ensures all costs, including Shared Costs, allocated to the OPDC rate classes reflect the fixed assets specifically used in the current OPDC service territory.

a) Please provide the following with respect to the Applicants' proposed cost allocation methodology:

   i. The Distribution Rate Cost Allocation Model reviewed by Navigant and referenced in their report.

   ii. The Applicants' proposed adjustment factors, the formula and inputs used in their calculation, as well as a description of the rationale that supports their reasonableness.

b) Using the Applicants' proposed Distribution Rate Cost Allocation Model (as referenced in the Navigant Report), please calculate the Total Residual Cost to Serve OPDC ensuring that the calculation reflects all applicable costs, including, but not limited to, Low Voltage charges as well as an appropriate allocation of Shared Costs. The result of the calculation should be a reasonable estimate based on sound assumptions of the costs to serve the current OPDC service territory following the rebasing deferral period (i.e., post-Year 10).

   i. In response to this question, the Applicants are requested to fully describe the process used by the Applicants to determine the appropriate allocation of Shared Costs to OPDC and clearly demonstrate how these Shared Costs are reflected in the allocation model.

c) If the result of the calculation undertaken in response to part b) is greater than $14.4 million, please discuss the implications of the result in terms of the proposed acquisition satisfying the conditions of the "no harm" test.

d) Please confirm, and provide reasoning/evidence, that as a result of the estimate undertaken in response to part b), legacy Hydro One customers would not be subsidizing any costs that should be allocated to current OPDC customers post-rebasing deferral period.

e) Please explain and demonstrate how Hydro One's proposed allocation methodology is consistent with the guidance provided by the OEB in its *Report of the Board on Application of Cost Allocation for Electricity Distributors* with respect to moving revenue-to-cost ratios closer to one.

**Response:**

a)

i) The Distribution Rate Cost Allocation Model reviewed by Navigant and referenced in their report was provided in MS Excel format as Q-01-01-03.xlsx in Hydro One's 2018-2022 distribution rate application (EB-2017-0049) on December 21, 2017. It is also provided as Attachment 1 to this response for convenience.

ii) In response to part b) of this question, Hydro One has prepared a 2030 Cost Allocation Model (2030 CAM) to show how costs would be allocated to OPDC in year 11 and to estimate the Notional Post-Rebasing Deferral Period Rates (NPRDPR) for responding to Exhibit I, Tab 1, Schedule 10.

The fixed asset adjustment factors used in the 2030 CAM for the OPDC rate classes are listed in Tables 1 and 2.

Table 1: GFA Adjustment Factors*

| Rate Class | Residential (AUR) | **GS < 50kW** ( AUGe) | **GS > 50 kW** (AUGd) |
|---|---|---|---|
| Factor | 32.4% | 24.6% | 17.3% |

Table 2: NFA and NFA Excluding Capital Contributions Adjustment Factors

| Rate Class | Residential (AUR) | **GS < 50kW** ( AUGe) | **GS > 50 kW** (AUGd) |
|---|---|---|---|
| Factor | 34.1% | 26.7% | 20.7% |

** The GFA adjustment factors are also used to adjust the deprecation amounts allocated to the OPDC rate classes.*

The derivation of Hydro One's proposed adjustment factors used in the 2030 CAM to modify the gross fixed asset (GFA), net fixed assets (NFA) and depreciation expense allocated to OPDC customer classes in year 11 is provided in MS Excel format as Attachment 2 to this response. The following is a description of the worksheets in Attachment 2:

<u>Tab "1. Forecast OPDC GFA":</u> Provides the derivation of the 2030 GFA associated with USofA accounts 1815-1860 for OPDC. Hydro One's 2030 GFA forecast for OPDC used in this worksheet is calculated using OPDC's 2019 Year-end forecast of

GFA as the starting value. From 2020 until Year 11 (2030) the GFA includes capital expenditures as forecast by Hydro One as outlined in Exhibit A, Tab 2, Schedule 1, Table 1.

Tab "2. OPDC last CAM outputs": Provides information from OPDC's most recent Cost Allocation Model (filed in EB-2009-0273) used to determine how much of each USofA account 1815-1860 was allocated to the various rate classes.

Tab "3. Allocated Forecast OPDC GFA": Provides the proportion of the total 2030 GFA for accounts 1815-1860 that is associated with OPDC residential and general service rate classes.

Tab "4. Non Adj 2030 CAM outputs": Provides information on the 2030 GFA associated with USofA accounts 1815-1860 that is allocated to the OPDC rate classes by the CAM, and also distinguishes the bulk assets included in those accounts, from those that specifically serve the new OPDC rate classes

Tab "4.5. OPDC Upstream DX factor": Using OPDC's 2019 IRM Rate Generator Model (EB-2018-0061) filed on May 1, 2019, this worksheet determines the share of OPDC load that is supplied through upstream distribution facilities to properly allocate upstream distribution costs to the OPDC rate classes.

Tab "5. Determine Alloc for OPDC": Provides the derivation of the GFA Adjustment Factor for OPDC rate classes based on comparing the GFA that should be allocated to each new OPDC rate class against the GFA allocated to those classes by the CAM prior to any adjustments. The share of OPDC load supplied through upstream distribution facilities derived in worksheet 4.5 is used in this worksheet to determine the amount of upstream distribution ("bulk") assets allocated to the OPDC rate classes.

Tab "6. NFA": Provides the derivation of the NFA Adjustment Factors for each OPDC rate class based on the ratio of NFA to GFA as determined in the CAM.

Tab "7. Depn5705": Provides the derivation of the adjusted annual depreciation costs for the OPDC rate classes.

Given the critical role of fixed assets in the allocation of costs within the cost allocation model, and the fact that OPDC's customers are located within a defined service area, the use of adjustment factors within the cost allocation model is a way to ensure that the amount of fixed assets allocated to the OPDC rate classes matches the amount of fixed assets specifically used to serve the customers within their service area.[2] At the time of harmonization of OPDC, Hydro One will know the amount of fixed assets being used to serve the former OPDC service area. The use of adjustment factors will effectively directly allocate local fixed assets to OPDC rate classes in the cost allocation model to ensure a more accurate reflection of the fixed assets, and associated costs, required to serve OPDC customers.

b) Hydro One has prepared a 2030 Cost Allocation Model (2030 CAM) to calculate the costs to serve OPDC customers in year 11. While the results from the CAM are indicative of what the results could be in 2030, as detailed further below, a number of assumptions were required to estimate the CAM inputs in 2030 for both Hydro One legacy and OPDC rate classes.

The results of the 2030 CAM for the acquired rate classes are shown in the table below:

| | Residential (AUR) | GS < 50 kW (AUGe) | GS > 50 kW (AUGd) | Total |
|---|---|---|---|---|
| Allocated Costs | 5,370,979 | 1,744,685 | 2,462,920 | 9,578,584 |
| R/C Ratio from CAM* | 0.94 | 0.88 | 0.97 | |

** The CAM R/C ratios for all rate classes are used in the rate design process provided in the response to Exhibit I, Tab 1, Schedule 10, as they are already within the Board's approved R/C ratio range.*

[2] Further rationale on the use of adjustment factors is provided in this application at Exhibit A, Tab 5, Schedule 1, section 4.0 (b) and Exhibit A, Tab 5, Schedule 1, Appendix A, page 5 to 6, and in EB-2017-0049 at Exhibit G1, Tab 3, Schedule 1, section 2.2.3 and Exhibit Q, Tab 1, Schedule 1, section 2.2.1

The total costs allocated to the OPDC Residential and GS acquired rate classes is $9.6M. A further $0.6M[3] in costs are estimated to be allocated to the OPDC customers that will be included in the Hydro One Street Lights, Sentinel Lights and USL rate classes ("combined classes"). The total cost of $10.2M for OPDC customers is below the OPDC cost to serve (Status Quo cost plus LV charges) of $14.4M.

The 2030 CAM allocates Hydro One's total revenue requirement, which includes the Residual Cost associated with serving OPDC customers, to all rate classes using the principles embedded in the OEB's cost allocation model. To appropriately allocate costs to the OPDC rate classes, Hydro One uses adjustment factors (as described in part a) to effectively directly allocate the amount of local fixed assets (USofA 1815 to 1860) used in serving the OPDC rate classes in 2030. The accurate allocation of fixed assets to the OPDC classes is key to ensuring that an appropriate share of Hydro One's total costs are allocated to the OPDC classes using the principles embedded in the OEB's cost allocation model.

Shared assets associated with upstream distribution facilities used by OPDC customers are allocated to the OPDC rate classes as described above in part a) ii). All remaining Shared costs are allocated to all rate classes, including both legacy and OPDC rate classes, on the same basis using the principles and allocators embedded within the OEB's cost allocation model for the allocation of such costs.

The following is a description of the key inputs and assumptions used to populate the 2030 CAM. The 2030 CAM is based on the 2021 CAM used in EB-2017-0049, with the following modifications:

- 2030 Revenue Requirement:

    Hydro One legacy customers: The average annual growth rate from 2017[4] to 2022 as approved in the EB-2017-0049 Decision[5] is used to project the 2030

[3] This amount is determined based on OPDC's forecast electricity usage of the Street Lights, Sentinel Lights, and USL classes relative to Hydro One's forecast electricity usage for these classes.
[4] 2017 approved revenue requirement as per EB-2016-0081.
[5] As submitted in Hydro One's Draft Rate Order filed April 5, 2019.

revenue requirement.

OPDC customers: Used the 2030 Residual revenue requirement as per Exhibit A, Tab 4, Schedule 1, Table 4.

- 2029 Rates (used to determine Revenue at Existing Rates in CAM):

  Hydro One legacy customers: The average annual growth in rates, by class, over the period from 2018 to 2022 as approved in the EB-2017-0049 Decision are used to project the 2029 rates.

  OPDC customers: The 2029 rates are based on current (2019) rates that are held constant for 2020-2024 and then increased by 1.55% under IRM for 2025 to 2029.

- Fixed Assets/Rate Base:

  Hydro One legacy customers: The average annual growth rate from 2017 to 2022 as approved in EB-2017-0049 Decision is used to project the 2030 fixed asset and rate base values.

  OPDC customers: Used the 2030 Residual asset values as per Exhibit A, Tab 2, Schedule 1, Attachment 18.

- Charge Determinants and CP/NCP Demand Data:

  Hydro One legacy customers: The annual growth rate from 2018 to 2022 as per EB-2017-00049 Decision is used to project the 2030 values.

  OPDC customers: Used the 2030 forecast consistent with forecast used in the Earning Sharing Mechanism model. The CP/NCP values from OPDC's last cost allocation model (2010) were scaled to match the growth in OPDC's 2010 to 2030 load forecast.

- New OPDC Rate Classes:
  - Acquired Urban Residential (AUR) - All OPDC Residential customers go to AUR
  - Acquired Urban General Service less than 50kW (AUGe) – All OPDC GS <50 kW customers go to AUGe
  - Acquired Urban General Service 50 to 4,999kW (AUGd) – All OPDC GS 50 to 4,999kW customers go to AUGd

The 2030 CAM is provided as Attachment 3 to this response.

c) The total cost allocated to OPDC customers, as discussed in part a), is less than the OPDC cost to serve (Status Quo plus LV charges) of $14.4 million.

d) Hydro One's legacy customer classes will not subsidize the OPDC acquired classes. With the proposed R/C ratios for all OPDC rate classes (which are within the Board's approved R/C ratio, as shown in Exhibit I, Tab 1, Schedule 10), a total revenue of $9.6M will be collected from OPDC customers. Since the total Residual Cost to serve including LV charges is $7.9M and the OPDC 2030 Status Quo cost including LV charges is $14.4M, the collection of $9.6M from OPDC customers means that legacy customers are benefitting from a reduction of $1.7M ($9.6M - $7.9M) in revenue collected, while OPDC customers are benefitting from a reduction of $4.8M ($14.4M - $9.6M) relative to what they would pay if OPDC is not acquired.

e) The OEB's *Report of the Board on Application of Cost Allocation for Electricity Distributors* issued March 31, 2011 premises the move of R/C ratios closer to 1 as being conditional on improved cost allocations. Hydro One does not contemplate any substantive changes to the cost allocation model for its existing rate classes and the introduction of new classes within the model further complicates the process of allocating costs across all of Hydro One's rate classes. As such, Hydro One believes the existing R/C ratio ranges are appropriate and provide utilities the needed flexibility to manage the rate impacts to their customers. Hydro One is also cognizant, and supportive, of the Board's view as expressed on page 4 of in their Report on *Application of Cost Allocation for Electricity Distributors* (EB-2007-0067) which states " a revenue-to-cost ratio of one may not be achievable or desirable for other reasons (for example, to accommodate different rate design objectives)". In this case, Hydro One believes the Board's approved R/C ratio ranges provide Hydro One the flexibility to ensure that the rates established for OPDC at the time of harmonization (Year 11) will reflect a sharing of the acquisition benefits between Hydro One legacy and OPDC customers.

# OEB STAFF INTERROGATORY # 10

**<u>Reference:</u>**
Exhibit A-5-1
Decision and Order on EB-2016-0276

**<u>Interrogatory:</u>**
**Preamble:**
At Exhibit A-5-1 p. 1, the Applicants state:

> The purpose of this Supplemental Evidence is to explain in detail Hydro One's proposed cost allocation and rate design for OPDC customers at the end of the rebasing deferral period. The Supplemental Evidence demonstrates that the application of Hydro One's proposed cost allocation and rate design to OPDC customers in a Year 11 rebasing will: (a) result in an allocation of costs to OPDC customers that reflects the cost to serve them; (b) ***result in rates that collect costs from OPDC customers that are less than what those customers would have paid in the absence of the proposed transaction***; and (c) leave Hydro One legacy customers unharmed or slightly better off than they would have been in the absence of the proposed transaction. In fact, the outcome of the cost allocation model and rate design reflects the sharing of cost savings in Year 11 and beyond for the benefit of both OPDC and Hydro One legacy customers. **[*Emphasis added*]**

***-and-***

**Preamble:**
At page 12 of the Decision and Order on EB-2016-0276, the OEB states:

> ***<u>One of the key considerations in the no harm test is protecting customers with respect to the prices they pay for electricity service</u>***. Although the Handbook states that "rate setting" following a consolidation will not be considered as part of a section 86 application, that does not mean the OEB will not consider the costs that acquired customers will have to pay following an acquisition (both in the short term and the long term). ***<u>Indeed the Handbook is clear that the underlying cost structures and</u>***

***the rate implications of those cost structures will be a key consideration.*** **[*Emphasis added*]**

OEB staff's focus is on understanding how the application of the proposed cost allocation, as defined by the Applicants in response to OEB Staff-9, is likely to impact the post-rebasing deferral period electricity bills of current OPDC customers.

To illustrate post-rebasing deferral period impacts, the Applicants are requested to create what OEB staff refers to as a Notional Post-Rebasing Deferral Period Rate (NPRDPR). The NPRDPR serves a fundamental purpose: it will allow the Applicants to forecast, based on their proposed allocation methodology, the monthly bill of a typical OPDC customer post-rebasing deferral period. The intent of the NPRDPR is to enable a legitimate forecast comparison between the typical OPDC customer's current and post-acquisition monthly bill. In-turn, a determination on the performance of the proposed transaction against a primary component of the "no harm" test can be made.

Below, OEB staff describes the methodology the Applicants should follow to produce the NPRDPR and subsequent bill comparison.

**Computing the NPRDPR and Performing the Comparison**

The NPRDPR will be used by the Applicants to demonstrate the bill impacts of the proposed acquisition if the post-rebasing deferral period electricity rate ***came into effect today***.

At Attachment 7 of the original application, the Applicants provided bill impact tables for the following OPDC customer types:

1. Residential
2. General Service Less Than 50kW
3. General Service 50 to 4,999 kW

Specifically, for each of the three customer types listed above, the Applicants are requested to compare the current typical monthly bill with that calculated using the NPRDPR methodology.

**Components of the NPRDPR Comparison**

The NPRDPR requires the Applicants to quantify both the savings and costs that they reasonably believe will be experienced by OPDC customers at the end of the rebasing deferral period. OEB staff's expectation is that the savings and costs used to develop the NPRDPR will be the same as those used by the Applicants to inform their response to OEB Staff-9.

Boxes 1 and 2 demonstrate the inputs the Applicants can use when developing the estimates for the pre- and post-acquisition bill impacts.

**Box 1: Current Customer Bill Calculations**

- For purposes of illustrating the current typical monthly OPDC customer bill, OEB staff expects that the Applicants can rely on the values already provided in the Customer Bill Impacts Tables found at Attachment 7 of the original application.
    - i.e., no additional calculations are likely required given that the columns labelled "Current Rates" and "Current Charges ($)" in these tables already demonstrate the typical inputs into the OPDC customer's monthly bill.
- The Applicants may elect to update the values in these tables for items such as current time-of-use electricity prices. If updates to values are made, OEB staff requests that the Applicants fully explain the rationale for the change.

**Box 2: NPRDPR Calculations**

- The NPRDPR represents the Current Typical Monthly Bill (inclusive of Low Voltage charges), adjusted to reflect the financial impacts of acquisition-related efficiencies (e.g., OM&A cost reductions) and Hydro One loss factors ***as well as*** an appropriate allocation of Hydro One Shared Costs to each customer group.

  Importantly, the calculation of the NPRDPR should ***not*** include any acquisition related short-term customer benefit such as the Applicants' proposed guaranteed earnings sharing mechanism or the 1% distribution rate discount.

- For demonstrative purposes, the Residential bill impacts table provided at Attachment 7, page 1 of the original application, has been recreated below to illustrate how the results of the NPRDPR analysis can be presented. When responding, the Applicants may choose to revise the tables as appropriate to clearly demonstrate how the NPRDPR monthly bill calculation reflects both the savings and costs experienced by OPDC customers as a result of the acquisition.

- Below, within the reproduced Attachment 7 table, OEB staff have highlighted in green the values that are likely to change as a result of this comparative exercise. Cells highlighted in grey represent values that OEB staff do not anticipate the comparison will impact. Note that these are assumptions only and the Applicants should update NPRDPR values as necessary to ensure an accurate comparison of pre- and post-rebasing deferral period bill impacts is created.

**Questions:**

a) Applying the same cost allocation approach created in response to OEB Staff-9, calculate the typical monthly bill for each of the three customer types shown in Attachment 7.

b) Please provide the resultant revenue to cost ratios for each of the three customer types/rate classes.

## Example Comparison Reporting Table

| | Residential | | | | | |
|---|---|---|---|---|---|---|
| | **Volume** | **Current Rates** | **Current Charges ($)** | **Rates as per NPRDPR** | **Charges per NPRDPR ($)** | **% Change** |
| **Monthly Consumption (kWh)** | 750 | | | 750 | 750 | |
| **Total Loss Factors** | 1.0561 | | | | | |
| | | | | | | |
| TOU - Off Peak Consumption | 488 | $0.065 | $ 31.69 | $0.065 | $ 31.69 | |
| TOU - Mid Peak Consumption | 128 | $0.094 | $ 11.99 | $0.094 | $ 11.99 | |
| TOU - On Peak Consumption | 135 | $0.132 | $ 17.82 | $0.132 | $ 17.82 | |
| **Total: Commodity** | | | **$ 61.49** | | **$ 61.49** | |
| | | | | | | |
| DX Fixed Charge | 1 | $18.9800 | $ 18.98 | | | |
| DX Fixed Charge Rate Riders | 1 | $0.0000 | $ - | | | |
| DX Vol. Charge ($/kWh) | 750 | $0.0047 | $ 3.53 | | | |
| DX Low Voltage Charge ($/kWh) | 750 | $0.0010 | $ 0.75 | | | |
| DX Vol. Rate Riders ($/kWh) | 750 | -$0.0009 | $ (0.68) | | | |
| **Distribution Rates Only** | | | **$ 22.58** | | | |
| | | | | | | |
| Smart Meter Entity Charge | 1 | $0.57 | $ 0.57 | $0.57 | $ 0.57 | |
| Cost of Losses | 42 | 0.082 | $ 3.37 | | | |
| **Distribution Pass Through Charges** | | | **$ 3.94** | | | |
| **Total: Distribution** | | | **$ 26.52** | | | |
| | | | | | | |
| TX - Network ($/kWh) | 792 | $0.0073 | $ 5.78 | | | |
| TX - Connection ($/kWh) | 792 | $0.0061 | $ 4.83 | | | |
| **Total: Transmission** | | | **$ 10.60** | | | |
| | | | | | | |
| WMSC ($/kWh) | 792 | $0.0036 | $ 2.85 | | | |
| RRRP ($/kWh) | 792 | $0.0003 | $ 0.24 | | | |
| SSA ($) | 1 | $0.25 | $ 0.25 | | | |
| **Total: Regulatory** | | | **$ 3.34** | | | |
| | | | | | | |
| Total Bill (Before Taxes) | | | $ 101.95 | | | |
| HST | | 13% | $ 13.25 | 13% | | |
| OREC | | -8% | $ (8.16) | -8% | | |
| **Total Bill (Including HST and OREC)** | | | **$ 107.05** | | | |

**Response:**

Hydro One has provided an estimate of the 2030 rates using the NPRDPR assumptions provided in the question but does not believe that comparing rates based on estimates made for both utilities that far into the future is required to satisfy the No Harm Test.

While Hydro One has provided the requested comparison in the response to part a), a more appropriate assessment of the impact of the acquisition on customer rates is to compare Hydro One's estimated 2030 rates with the 2030 Status Quo rates if OPDC had not been acquired, which is provided in Exhibit I, Tab 1, Schedule 11.

a) Attachment 1 to this response provides the requested bill impacts. Hydro One has added columns to the table to show Year 10 (2029) rates, with consolidation, in order to accurately reflect the bill impacts that OPDC customers are forecast to see in 2030. OPDC's 2029 customers' rates are their existing 2019 rates plus five years of IRM increases (the 5-year period after the rate freeze).

b) Using the output results from the 2030 Cost Allocation Model (CAM) (as described in Exhibit I, Tab 1, Schedule 9), Hydro One has prepared a 2030 Rate Design model to calculate the rates and revenue-to-cost (R/C) ratios in year 11 (see Attachment 2 to this response). As shown in the table below, R/C ratios resulting from 2030 CAM are within the Board approved range for the proposed OPDC rate classes, and hence, no further adjustment were made to the R/C ratios.

| Rate Class | R/C Ratio from CAM | Proposed R/C Ratio from Rate Design | Board Approved R/C Ratio Range |
|---|---|---|---|
| Residential | 0.94 | 0.94 | 0.85 to 1.15 |
| GS < 50kW | 0.88 | 0.88 | 0.80 to 1.20 |
| GS 50-4,999 kW | 0.97 | 0.97 | 0.80 to 1.20 |

At the proposed R/C ratios, the estimated revenue collected from OPDC customers in 2030 will be \$9.6M (\$9.0M from customers in the proposed OPDC rate classes and an estimated \$0.6M from OPDC customers in the "combined" rate classes). The amount to be collected from OPDC customers is between the year 11 total Residual cost to serve including LV charges (\$7.9M) and the total OPDC Status Quo including LV charges (\$14.4M). Since the revenue collected from the OPDC customers falls between these two amounts, both Hydro One legacy and OPDC customers will benefit from the acquisition of OPDC. Hydro One legacy customers will see a benefit of $1.7M ($9.6M - $7.9M) in revenue that would otherwise be collected from them if OPDC is not acquired. OPDC customers will see a benefit of $4.8M ($14.4M - $9.6M) that would otherwise be collected from them if OPDC is not acquired.

| | Residential | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Volume | Current (2019) Rates[1] | Current (2019) Charges ($) | Year 10 (2029) Rates | Year 10 (2029) Charges ($) | Rates as per NPRDPR (2030) | Charges per NPRDPR (2030) ($) | % Change (Year 11 over Current Rates) | % Change (Year 11 over Year 10) |
| **Monthly Consumption (kWh)** | **750** | | | | | | | | |
| **Total Loss Factors** | **1.0561** | | | | | | | | |
| | | | | | | | | | |
| TOU - Off Peak Consumption ($/kWh) | 488 | $0.065 | $31.69 | $0.065 | $31.69 | $0.065 | $31.69 | | |
| TOU - Mid Peak Consumption ($/kWh) | 128 | $0.094 | $11.99 | $0.094 | $11.99 | $0.094 | $11.99 | | |
| TOU - On Peak Consumption ($/kWh) | 135 | $0.134 | $18.09 | $0.134 | $18.09 | $0.134 | $18.09 | | |
| **Total: Commodity** | | | **$61.76** | | **$61.76** | | **$61.76** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| DX Fixed Charge ($) | 1 | $27.93 | $27.93 | $30.38 | $30.38 | $29.36 | $29.36 | | |
| DX Fixed Charge Rate Riders ($) | 1 | $2.56 | $2.56 | $2.56 | $2.56 | $0.00 | $0.00 | | |
| DX Vol. Charge ($/kWh) | 750 | $0.0000 | $0.00 | $0.0000 | $0.00 | $0.00 | $0.00 | | |
| DX Low Voltage Charge ($/kWh) | 750 | $0.0006 | $0.45 | $0.0032 | $2.40 | $0.00 | $0.00 | | |
| DX Vol. Rate Riders ($/kWh) | 750 | $0.0000 | $0.00 | $0.0000 | $0.00 | $0.00 | $0.00 | | |
| **Distribution Rates Only** | | | **$30.94** | | **$35.34** | | **$29.36** | **-5.1%** | **-16.9%** |
| | | | | | | | | | |
| Smart Meter Entity Charge | 1 | $0.57 | $0.57 | $0.57 | $0.57 | $0.57 | $0.57 | | |
| Cost of Losses | 42 | $0.082 | $3.46 | $0.082 | $3.46 | $0.082 | $3.46 | | |
| **Distribution Pass Through Charges** | | | **$4.03** | | **$4.03** | | **$4.03** | | |
| **Total: Distribution** | | | **$34.97** | | **$39.37** | | **$33.39** | **-4.5%** | **-15.2%** |
| | | | | | | | | | |
| TX - Network ($/kWh) | 792 | $0.0050 | $3.96 | $0.0050 | $3.96 | $0.0050 | $3.96 | | |
| TX - Connection ($/kWh) | 792 | $0.0039 | $3.09 | $0.0039 | $3.09 | $0.0039 | $3.09 | | |
| **Total: Transmission** | | | **$7.05** | | **$7.05** | | **$7.05** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| WMSC ($/kWh) | 792 | $0.0034 | $2.69 | $0.0034 | $2.69 | $0.0034 | $2.69 | | |
| RRRP ($/kWh) | 792 | $0.0005 | $0.40 | $0.0005 | $0.40 | $0.0005 | $0.40 | | |
| SSA ($) | 1 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | | |
| **Total: Regulatory** | | | **$3.34** | | **$3.34** | | **$3.34** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| Total Bill (Before Taxes) | | | $107.13 | | $111.53 | | $105.55 | | |
| HST | | 13% | $13.93 | 13% | $14.50 | 13% | $13.72 | | |
| OREC | | -8% | -$8.57 | -8% | -$8.92 | -8% | -$8.44 | | |
| **Total Bill (Including HST and OREC)** | | | **$112.48** | | **$117.10** | | **$110.82** | **-1.5%** | **-5.4%** |

[1] Excludes Tax Change rider.

| | General Service Less Than 50 kW | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Volume | Current (2019) Rates[1] | Current (2019) Charges ($) | Year 10 (2029) Rates | Year 10 (2029) Charges ($) | Rates as per NPRDPR (2030) | Charges per NPRDPR (2030) ($) | % Change (2030 over 2019) | % Change (2030 over 2029) |
| **Monthly Consumption (kWh)** | **2,000** | | | | | | | | |
| **Total Loss Factors** | **1.0561** | | | | | | | | |
| | | | | | | | | | |
| TOU - Off Peak Consumption ($/kWh) | 1,300 | $0.065 | $84.50 | $0.065 | $84.50 | $0.065 | $84.50 | | |
| TOU - Mid Peak Consumption ($/kWh) | 340 | $0.094 | $31.96 | $0.094 | $31.96 | $0.094 | $31.96 | | |
| TOU - On Peak Consumption ($/kWh) | 360 | $0.134 | $48.24 | $0.134 | $48.24 | $0.134 | $48.24 | | |
| **Total: Commodity** | | | **$164.70** | | **$164.70** | | **$164.70** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| DX Fixed Charge ($) | 1 | $37.42 | $37.42 | $40.71 | $40.71 | $39.34 | $39.34 | | |
| DX Fixed Charge Rate Riders ($) | 1 | $7.48 | $7.48 | $7.48 | $7.48 | $0.00 | $0.00 | | |
| DX Vol. Charge ($/kWh) | 2,000 | $0.0165 | $33.00 | $0.0179 | $35.80 | $0.0173 | $34.60 | | |
| DX Low Voltage Charge ($/kWh) | 2,000 | $0.0006 | $1.20 | $0.0032 | $6.40 | $0.0000 | $0.00 | | |
| DX Vol. Rate Riders ($/kWh) | 2,000 | $0.0000 | $0.00 | $0.0000 | $0.00 | $0.0000 | $0.00 | | |
| **Distribution Rates Only** | | | **$79.10** | | **$90.39** | | **$73.94** | **-6.5%** | **-18.2%** |
| | | | | | | | | | |
| Smart Meter Entity Charge | 1 | $0.57 | $0.57 | $0.57 | $0.57 | $0.57 | $0.57 | | |
| Cost of Losses | 112 | $0.082 | $9.24 | $0.082 | $9.24 | $0.082 | $9.24 | | |
| **Distribution Pass Through Charges** | | | **$9.81** | | **$9.81** | | **$9.81** | | |
| **Total: Distribution** | | | **$88.91** | | **$100.20** | | **$83.75** | **-5.8%** | **-16.4%** |
| | | | | | | | | | |
| TX - Network ($/kWh) | 2,112 | $0.0042 | $8.87 | $0.0042 | $8.87 | $0.0042 | $8.87 | | |
| TX - Connection ($/kWh) | 2,112 | $0.0037 | $7.82 | $0.0037 | $7.82 | $0.0037 | $7.82 | | |
| **Total: Transmission** | | | **$16.69** | | **$16.69** | | **$16.69** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| WMSC ($/kWh) | 2,112 | $0.0034 | $7.18 | $0.0034 | $7.18 | $0.0034 | $7.18 | | |
| RRRP ($/kWh) | 2,112 | $0.0005 | $1.06 | $0.0005 | $1.06 | $0.0005 | $1.06 | | |
| SSA ($) | 1 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | | |
| **Total: Regulatory** | | | **$8.49** | | **$8.49** | | **$8.49** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| Total Bill (Before Taxes) | | | $278.78 | | $290.07 | | $273.62 | | |
| HST | | 13% | $36.24 | 13% | $37.71 | 13% | $35.57 | | |
| OREC | | -8% | -$22.30 | -8% | -$23.21 | -8% | -$21.89 | | |
| **Total Bill (Including HST and OREC)** | | | **$292.72** | | **$304.58** | | **$287.30** | **-1.9%** | **-5.7%** |

[1] Excludes Tax Change rider.

| | General Service 50-4,999 kW | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Volume** | **Current (2019) Rates** | **Current (2019) Charges ($)** | **Year 10 (2029) Rates** | **Year 10 (2029) Charges ($)** | **Rates as per NPRDPR (2030)** | **Charges per NPRDPR (2030) ($)** | **% Change (2030 over 2019)** | **% Change (2030 over 2029)** |
| **Monthly Consumption (kWh)** | **73,000** | | | | | | | | |
| **Peak (kW)** | **100** | | | | | | | | |
| **Total Loss Factors** | **1.0561** | | | | | | | | |
| | | | | | | | | | |
| 12-Month Average WAHSP (2018) ($/kWh) | 77,095 | $0.1157 | $8,922.50 | $0.1157 | $8,922.50 | $0.1157 | $8,922.50 | | |
| **Total: Commodity** | | | **$8,922.50** | | **$8,922.50** | | **$8,922.50** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| DX Fixed Charge ($) | 1 | $340.60 | $340.60 | $370.45 | $370.45 | $357.98 | $357.98 | | |
| DX Fixed Charge Rate Riders ($) | 1 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | | |
| DX Vol. Charge ($/kW) | 100 | $3.5825 | $358.25 | $3.8965 | $389.65 | $3.7653 | $376.53 | | |
| DX Low Voltage Charge ($/kW) | 100 | $0.2230 | $22.30 | $1.1934 | $119.34 | $0.0000 | $0.00 | | |
| DX Vol. Rate Riders ($/kW) | 100 | $0.0000 | $0.00 | $0.0000 | $0.00 | $0.0000 | $0.00 | | |
| **Total: Distribution** | | | **$721.15** | | **$879.44** | | **$734.51** | **1.9%** | **-16.5%** |
| | | | | | | | | | |
| TX - Network ($/kW) | 100 | $1.8667 | $186.67 | $1.8667 | $186.67 | $1.8667 | $186.67 | | |
| TX - Connection ($/kW) | 100 | $1.4700 | $147.00 | $1.4700 | $147.00 | $1.4700 | $147.00 | | |
| **Total: Transmission** | | | **$333.67** | | **$333.67** | | **$333.67** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| WMSC ($/kWh) | 77,095 | $0.0034 | $262.12 | $0.0034 | $262.12 | $0.0034 | $262.12 | | |
| RRRP ($/kWh) | 77,095 | $0.0005 | $38.55 | $0.0005 | $38.55 | $0.0005 | $38.55 | | |
| SSA ($) | 1 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | $0.25 | | |
| **Total: Regulatory** | | | **$300.92** | | **$300.92** | | **$300.92** | **0.0%** | **0.0%** |
| | | | | | | | | | |
| Total Bill (Before Taxes) | | | $10,278.24 | | $10,436.53 | | $10,291.60 | | |
| HST | | 13% | $1,336.17 | 13% | $1,356.75 | 13% | $1,337.91 | | |
| OREC | | 0% | $0.00 | 0% | $0.00 | 0% | $0.00 | | |
| **Total Bill (Including HST and OREC)** | | | **$11,614.41** | | **$11,793.28** | | **$11,629.51** | **0.1%** | **-1.4%** |

## 2030 Rate Design (EB-2018-0270)

| | Number of Customers | GWh | kWs | Revenue (A) | Allocated Costs (B) | (%) | Misc Rev (C) | Revenue from Rates (D=A-C) | 2022 R/C Ratio (E) | R/C Ratio from the CAM (F=A/B) | Target 2030 R/C Ratio (G) | Total rev to be collected (H=BxG) | Shifted Rev (I=H-A) | % Change in revenue from rates (J=I/D) | Fixed Charge ($/month) | Revenue from Fixed Charge (K) | Fixed Rev % | Revenue from Volumetric Charge (L=H-C-K) | Volumetric Charge ($/kWh) | Volumetric Charge ($/kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| UR | 261,362 | 1,993 | | $ 137,202,655 | $ 121,580,909 | 6.34% | $ 4,704,001 | $ 132,498,654 | 1.12 | 1.13 | 1.13 | 137,202,655 | - | 0.0% | $ 42.25 | $ 132,498,654 | 100% | $ - | $ - | |
| R1 | 495,300 | 4,676 | | $ 432,466,538 | $ 392,823,725 | 20.50% | $ 12,281,233 | $ 420,185,306 | 1.12 | 1.10 | 1.10 | 432,466,538 | - | 0.0% | $ 70.70 | $ 420,185,306 | 100% | $ - | $ - | |
| R2 | 349,752 | 3,869 | | $ 675,819,376 | $ 677,397,157 | 35.34% | $ 14,283,439 | $ 661,535,936 | 0.97 | 1.00 | 1.00 | 675,819,376 | - | 0.0% | $ 157.62 | $ 661,535,936 | 100% | $ - | $ - | |
| Seasonal | 151,486 | 489 | | $ 135,584,550 | $ 125,873,466 | 6.57% | $ 2,709,298 | $ 132,875,252 | 1.07 | 1.08 | 1.08 | 135,584,550 | - | 0.0% | $ 73.10 | $ 132,875,252 | 100% | $ - | $ - | |
| GSe | 86,717 | 1,849 | | $ 184,551,482 | $ 195,223,787 | 10.19% | $ 4,308,286 | $ 180,243,196 | 0.94 | 0.95 | 0.95 | 184,551,482 | - | 0.0% | $ 35.01 | $ 36,429,325 | 20% | $ 143,813,871 | $ 0.0778 | |
| GSd | 5,775 | 2,264 | 7,401,712 | $ 171,413,240 | $ 216,267,799 | 11.28% | $ 2,596,836 | $ 168,816,404 | 0.88 | 0.79 | 0.79 | 171,413,240 | - | 0.0% | $ 115.17 | $ 7,981,131 | 5% | $ 160,835,273 | | $ 21.7295 |
| UGe | 19,046 | 561 | | $ 28,015,108 | $ 29,973,096 | 1.56% | $ 781,407 | $ 27,233,702 | 0.99 | 0.93 | 0.93 | 28,015,108 | - | 0.0% | $ 28.25 | $ 6,457,363 | 24% | $ 20,776,338 | $ 0.0370 | |
| UGd | 1,829 | 975 | 2,323,345 | $ 31,919,505 | $ 39,265,064 | 2.05% | $ 529,024 | $ 31,390,481 | 0.87 | 0.81 | 0.81 | 31,919,505 | - | 0.0% | $ 103.33 | $ 2,267,795 | 7% | $ 29,122,686 | | $ 12.5348 |
| St Lgt | 5,930 | 102 | | $ 13,555,619 | $ 14,591,332 | 0.76% | $ 263,138 | $ 13,292,480 | 0.93 | 0.93 | 0.93 | 13,555,619 | - | 0.0% | $ 4.01 | $ 285,448 | 2% | $ 13,007,033 | $ 0.1270 | |
| Sen Lgt | 20,950 | 12 | | $ 5,630,365 | $ 5,664,040 | 0.30% | $ 1,952,683 | $ 3,677,682 | 0.94 | 0.99 | 0.99 | 5,630,365 | - | 0.0% | $ 3.96 | $ 995,876 | 27% | $ 2,681,806 | $ 0.2189 | |
| USL | 5,899 | 31 | | $ 3,713,032 | $ 3,678,741 | 0.19% | $ 112,125 | $ 3,600,906 | 1.11 | 1.01 | 1.01 | 3,713,032 | - | 0.0% | $ 39.21 | $ 2,775,508 | 77% | $ 825,398 | $ 0.0263 | |
| DGen | 3,043 | 39 | 284,678 | $ 11,801,406 | $ 10,910,980 | 0.57% | $ 273,895 | $ 11,527,511 | 0.87 | 1.08 | 1.08 | 11,801,406 | - | 0.0% | $ 196.16 | $ 7,163,667 | 62% | $ 4,363,844 | | $ 15.3290 |
| ST | 841 | 14,875 | 33,199,597 | $ 75,881,453 | $ 73,723,508 | 3.85% | $ 1,091,121 | $ 74,790,332 | 0.99 | 1.03 | 1.03 | 75,881,453 | - | 0.0% | $ 1,385.99 | $ 13,993,439 | 19% | $ 60,796,893 | | $ 1.8313 |
| AUR | 13,850 | 102 | | $ 5,073,009 | $ 5,370,979 | 0.28% | $ 193,915 | $ 4,879,094 | | 0.94 | 0.94 | 5,073,009 | - | 0.0% | $ 29.36 | $ 4,879,094 | 100% | $ - | $ - | |
| AUGe | 1,544 | 44 | | $ 1,538,976 | $ 1,744,685 | 0.09% | $ 43,216 | $ 1,495,760 | | 0.88 | 0.88 | 1,538,976 | - | 0.0% | $ 39.34 | $ 728,970 | 49% | $ 766,789 | $ 0.0173 | |
| AUGd | 180 | 159 | 415,504 | $ 2,385,875 | $ 2,462,920 | 0.13% | $ 47,363 | $ 2,338,513 | | 0.97 | 0.97 | 2,385,875 | - | 0.0% | $ 357.98 | $ 774,019 | 33% | $ 1,564,493 | | $ 3.7653 |
| | **1,423,504** | **32,041** | **43,624,837** | **$ 1,916,552,189** | **$ 1,916,552,189** | **100%** | **$ 46,170,979** | **$ 1,870,381,210** | | | | | **$ -** | | | **$ 1,431,826,785** | | **$ 438,554,425** | | |

| | |
|---|---|
| **Total Rev (K+L)** | **$ 1,870,381,210** |
| **Misc Rev (C)** | **$ 46,170,979** |
| **Total Rev Req** | **$ 1,916,552,189** |

# OEB STAFF INTERROGATORY # 11

**Reference:**

Exhibit A-4-1

**Interrogatory:**

**Questions:**

a) Please provide a table which compares indicative Hydro One and OPDC monthly electricity bills:

i. Today (e.g. 2019)
ii. In Year 10 with the proposed consolidation
iii. In Year 10 without the proposed consolidation
iv. In Year 11 with the proposed consolidation
v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, and General Service greater than 50 kW.

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, please ensure that they do.

c) Please also explain how costs have been allocated to OPDC customers in the response to part a) iv) above.

**Response:**

a) The tables below provide indicative monthly electricity bills for Hydro One Urban rate classes and OPDC's Residential and General Service customers for the requested scenarios. The total bill calculation excludes the "Rate Rider for Application of Tax Change" (Final Rate Order, EB-2018-0061) and ESM refund.

| OPDC | Today - 2019 | | Year10 - With Consolidation[1] | | Year10 - Without Consolidation[2] | | Year11 - With Consolidation[3] | | Year11 - Without Consolidation[2] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[4] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[4] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[4] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[4] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[4] |
| Residential (750kWh) | $30.94 | $112.48 | $35.34 | $117.10 | $48.97 | $131.41 | $29.36 | $110.82 | $50.25 | $132.75 |
| GS < 50kW (2,000kWh) | $79.10 | $292.72 | $90.39 | $304.58 | $123.80 | $339.66 | $73.94 | $287.30 | $127.00 | $343.02 |
| GS 50 to 4,999 kW (250kW) | $721.15 | $11,614.41 | $879.44 | $11,793.28 | $1,284.63 | $12,251.14 | $734.51 | $11,629.51 | $1,316.50 | $12,287.15 |

[1] Indicative distribution rates for year 10 (with consolidation) have been calculated by applying -1% to OPDC's exsting rates then holding them constant for 2020-2024 and then applying IRM increase of 1.7% for 2025-2029 (refer to Exhibit I, Tab 6, Schedule 17).

[2] Indicative distribution rates for year 10 and year 11 (without consolidation) have been calculated using the percentage increase in rates revenue requirement compared to 2019 (refer to Exhibit I, Tab 1, Schedule 12).

[3] Indicative distribution rates for year 11 (with consolidation) have been derived through the rate design process consistent with the cost allocation model provided in Exhibit I, Tab 1, Schedule 10, Attachement 2.

[4] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

| Hydro One | Today - 2019 | | Year10 - With Consolidation[1] | | Year10 - Without Consolidation[1] | | Year11 - With Consolidation[2] | | Year11 - Without Consolidation[1] | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[3] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[3] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[3] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[3] | Base Monthly Distribution Charges ($) | Monthly Total Bill ($)[3] |
| Residential (UR 750kWh) | $34.26 | $121.77 | $43.72 | $131.71 | $43.72 | $131.71 | $42.25 | $130.17 | $44.87 | $132.92 |
| GS < 50kW (UGe 2,000kWh) | $81.60 | $306.91 | $105.88 | $332.41 | $105.88 | $332.41 | $102.25 | $328.60 | $108.84 | $335.52 |
| GS > 50 kW (UGd 250kW) | $2,559.27 | $30,087.07 | $3,347.54 | $30,977.82 | $3,347.54 | $30,977.82 | $3,237.03 | $30,852.95 | $3,440.78 | $31,083.18 |

[1] Indicative distribution rates for year 10 (with and without consolidation) and year 11 (without consolidation) have been calculated using the compound annual growth rate between 2018 and 2022 and then applying it to 2022 rates.

[2] Indicative distribution rates for year 11 (with consolidation) have been derived through the rate design process consistent with the cost allocation model provided in Exhibit I, Tab 1,Schedule 10, Attachement 2.

[3] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

b) Confirmed.

c) Hydro One has produced a Cost Allocation Model (CAM) for Year 11 (2030) which allocates the total costs to various customer classes including proposed rate classes for OPDC's Residential and General Service customers. Please refer to Exhibit I, Tab 1, Schedule 9 for details and assumptions for this CAM run.

# OEB STAFF INTERROGATORY # 12

**Reference:**

Exhibit A-4-1

**Interrogatory:**

**Questions:**

a) Please provide a table which estimates Hydro One and OPDC revenue requirements and revenue requirements per customer:

i. Today (e.g. 2019)
ii. In Year 10 with the proposed consolidation
iii. In Year 10 without the proposed consolidation
iv. In Year 11 with the proposed consolidation, including all costs that are expected to be allocated to OPDC
v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, General Service greater than 50 kW and total of all customer types (i.e. total revenue requirement).

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, pleas ensure that they do.

**Response:**

a) The tables below provide the requested information for Hydro One's Urban rate classes and OPDC.

| OPDC | Today (2019)[1,2,3] | Year 10 (2029) with consolidation[2,3,4] | Year 10 (2029) without consolidation[2,3,5] | Year 11 (2030) with consolidation[6] | Year 11 (2030) without consolidation[2,3,7] |
|---|---|---|---|---|---|
| **Revenue Requirement** | | | | | |
| Residential | $4,471,729 | $4,886,300 | $7,110,967 | $5,073,009 | $7,281,348 |
| GS < 50kW | $1,623,718 | $1,779,756 | $2,602,179 | $1,538,976 | $2,665,364 |
| GS 50-4,999 kW | $2,400,644 | $2,676,069 | $3,798,964 | $2,385,875 | $3,889,680 |
| Other | $363,045 | $395,662 | $596,908 | $588,293 | $611,972 |
| **Total** | **$8,859,135** | **$9,737,786** | **$14,109,018** | **$9,586,153** | **$14,448,364** |
| | | | | | |
| **Revenue Requirement per Customer** | | | | | |
| Residential | $357 | $356 | $518 | $366 | $526 |
| GS < 50kW | $1,155 | $1,162 | $1,699 | $997 | $1,726 |
| GS 50-4,999 kW | $14,430 | $14,958 | $21,234 | $13,241 | $21,587 |
| Other | $90 | $95 | $143 | $140 | $146 |
| **Total** | **$489** | **$496** | **$719** | **$485** | **$731** |

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2010 and 2019 to the approved revenue collected from rates in 2010.

[2] External revenues are held constant at 2010 approved values.

[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected (refer to Exhibit I, Tab 3, Schedule 9).

[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.7% for 2025-2029.

[5] Total revenue collected (including external revenues) per Exhibit I, Tab 2, Schedule 17.

[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $0.6M in estimated revenue collected from the "combined classes").

[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

| Hydro One | Today (2019)[1] | Year 10 (2029) with consolidation[2,3] | Year 10 (2029) without consolidation[2,3] | Year 11 (2030) with consolidation[4] | Year 11 (2030) without consolidation[2,3] |
|---|---|---|---|---|---|
| **Revenue Requirement** | | | | | |
| Residential (UR) | $97,456,815 | $121,420,723 | $121,420,723 | $137,202,655 | $137,390,232 |
| GS<50kW (UGe) | $23,037,678 | $28,770,504 | $28,770,504 | $28,015,108 | $28,054,505 |
| GS>50kW (UGd) | $28,548,646 | $35,752,868 | $35,752,868 | $31,919,505 | $31,966,604 |
| Other | $1,348,816,751 | $1,685,459,484 | $1,685,459,484 | $1,709,828,767 | $1,712,281,421 |
| **Total** | **$1,497,859,890** | **$1,871,403,579** | **$1,871,403,579** | **$1,906,966,036** | **$1,909,692,763** |
| | | | | | |
| **Revenue Requirement per Customer** | | | | | |
| Residential (UR) | $424 | $469 | $469 | $525 | $526 |
| GS<50kW (UGe) | $1,276 | $1,520 | $1,520 | $1,471 | $1,473 |
| GS>50kW (UGd) | $16,413 | $19,665 | $19,665 | $17,452 | $17,478 |
| Other | $1,275 | $1,504 | $1,504 | $1,519 | $1,521 |
| **Total** | **$1,146** | **$1,337** | **$1,337** | **$1,354** | **$1,356** |

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $0.6M in estimated revenue collected from the "combined classes").

b) Confirmed.

# OEB STAFF INTERROGATORY # 13

**Reference:**
Exhibit A-2-1

**Interrogatory:**
**Preamble:**
At Exhibit A-2-1 p. 5, the Applicants state:

> All other OPDC tariffs will remain as approved in OPDC's last rate order; with the exception of Specific Service Charges ("SSCs") which Hydro One is seeking approval to amend to align with the SSCs as approved, or will be approved, by the OEB for Hydro One Distribution.

**Questions:**

a) Please prepare a table which compares the current OPDC Specific Service Charges with those that "…Hydro One is seeking approval to amend to align with the SSCs as approved, or will be approved, by the OEB for Hydro One Distribution"; please explain any differences.

b) Please identify any material differences in the current Conditions of Service of OPDC and Hydro One (as proposed at EB-2017-0049).

**Response:**

a) Please refer to Attachment 1 for a table outlining OPDC's Specific Service Charges, and those of Hydro One.

   Miscellaneous services are provided at a customer's request or as the result of a customer's action or inaction and impose costs on the distributor. In order to recover these costs, following a user-pays principle, distributors charge Specific Service Charges ("SSCs") to the relevant customer either at an OEB-approved rate (established using the OEB's 2006 Distribution Rate Handbook or by means of a rate order) or by using actual costs ("time and materials") of rendering the service. Many distributors' SSCs across the province have not been updated since 2006 and no longer reflect the true cost of rendering these services. The differences between the existing OPDC SSCs and Hydro One's SSCs, as shown in Attachment 1, are attributable to the fact that OPDC has not updated its SSC rates since the Handbook was issued/updated in 2006. In contrast, Hydro One, in its EB-2017-0049 rates application, provided a study supporting new SSCs as directed by the OEB. During that rates hearing intervenors provided feedback to Hydro One on the proposed new SSCs, which Hydro One updated in final argument. Hydro One believes that its SSCs shown in Attachment 1 are most representative of the current costs of providing these miscellaneous services so as to ensure that electricity ratepayers are not subsidizing the cost of providing such services to individual customers.

b) Material differences between the Conditions of Service of the two utilities have not been identified.

| Non-payment of account | OPDC Charge | Proposed Hydro One Charge Including Oral Hearing Updates in EB-2017-0049 |
|---|---|---|
| Late payment (interest charged on unpaid accounts) | 1.5% per month, 19.56% per annum | 1.5% per month, 19.56% per annum |
| Collection - reconnect at meter - during regular hours (8 am to 7 pm) | $65.00 | $65.00 |
| Collection - reconnect at meter - after regular hours | $185.00 | $185.00 |
| Collection - reconnect at pole - during regular hours (8 am to 4 pm) | $185.00 | $185.00 |
| Collection - reconnect at pole - after regular hours | $415.00 | $415.00 |

| Administration | Charge | Charge |
|---|---|---|
| Account set-up charge / change of occupancy charge (plus credit agency costs if applicable) | $30.00 | $38.00 |
| Statement of account (required when applying to waive deposit at new utility) | $15.00 | - |
| Easement letter | $15.00 | Letter Request - $86.90<br>Web Request - $25.00 |
| Income tax letter (statement of account for income tax purposes) | $15.00 | - |
| Account history | $15.00 | - |
| Credit reference / credit check (plus credit agency costs) (in lieu of deposit) | $15.00 | - |
| Returned cheque charge (plus bank charges) | $15.00 | $7.00 |
| Legal letter charge (required by lawyer during property sale) | $15.00 | - |
| Arrears certificate (letter of reference, credit history) | $15.00 | - |
| Special meter reads (unscheduled or reversed move-in or out) | $30.00 | $90.00 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $30.00 | $30 plus MC fee |
| Service call (customer-owned equipment) - during regular hours (8 am to 4:30 pm) | - | $210.00 |
| Service call (customer-owned equipment) - after regular hours | - | $775.00 |
| Temporary service install and/or remove - overhead - no transformer | $500.00 | Actual Costs |
| Temporary service install and/or remove - overhead - with transformer | $1,000.00 | Actual Costs |
| Temporary service install and/or remove - underground - no transformer | $300.00 | Actual Costs |
| Specific charge for access to the power poles ($ per pole per year) | Telecom $43.63 | Telecom $43.63 |
| **Hydro One Only** | **Charge** | **Charge** |
| Vacant Premise – Move in with Reconnect of Electrical Service at Meter | | - |
| Vacant Premise – Move in with Reconnect of Electrical Service at Pole | | - |
| Reconnect Completed after Regular Hours (Customer/Contract Driven) – at Meter | | $245.00 |
| Reconnect Completed after Regular Hours (Customer/Contract) Driven) – at Pole | | $475.00 |
| Additional Service Layout Fee – Basic/Complex (more than one hour) | | $569.51 |
| Pipeline Crossings | | $2,396.75 |
| Water Crossings | | $3,570.65 |
| Railway Crossings | | $4760.48 + Railway feedthrough costs |
| Overhead Line Staking Per Meter | | $4.24 |
| Underground Line Staking Per Meter | | $3.05 |
| Subcable Line Staking Per Meter | | $2.66 |
| Central Metering – New Service <45 kW | | $100.00 |
| Conversion to Central Metering <45 kW | | $1,533.47 |
| Conversion to Central Metering >=45 kW | | $1,453.47 |
| Connection Impact Assessments – Net Metering | | $3,192.85 |
| Connection Impact Assessments – Embedded LDC Generators | | $2,873.57 |
| Connection Impact Assessments - Small Projects <= 500 kW | | $3,266.07 |
| Connection Impact Assessments – Small Projects <= 500 kW, Simplified | | $1,971.27 |
| Connection Impact Assessments – Greater than Capacity Allocation Exempt Projects – Capacity Allocation Required Projects | | $8,641.91 |
| Connection Impact Assessments – Greater than Capacity Allocation Exempt Projects – TS Review for LDC Capacity Allocation Required Projects | | $5,727.89 |
| Specific Charge for Access to Power Poles – Municipal Streetlights | | $2.04 |
| Sentinel Light Rental Charge | | $10.00 |
| Sentinel Light Pole Rental Charge | | $7.00 |
| Specific Charge for LDCs Access to the Power Poles ($/pole/year) | | |

| Hydro One Only | Charge | Charge |
|---|---|---|
| LDC Rate for 10’ of power space | | $86.56 |
| LDC Rate for 15’ of power space | | $103.88 |
| LDC Rate for 20’ of power space | | $115.42 |
| LDC Rate for 25’ of power space | | $123.66 |
| LDC Rate for 30’ of power space | | $129.85 |
| LDC Rate for 35’ of power space | | $134.66 |
| LDC Rate for 40’ of power space | | $138.50 |
| LDC Rate for 45’ of power space | | $141.65 |
| LDC Rate for 50’ of power space | | $144.27 |
| LDC Rate for 55’ of power space | | $146.49 |
| LDC Rate for 60’ of power space | | $148.40 |
| Specific Charge for Generator Access to the Power Poles ($/pole/year) | | |
| Generator Rate for 10’ of power space | | $86.56 |
| Generator Rate for 15’ of power space | | $103.88 |
| Generator Rate for 20’ of power space | | $115.42 |
| Generator Rate for 25’ of power space | | $123.66 |
| Generator Rate for 30’ of power space | | $129.85 |
| Generator Rate for 35’ of power space | | $134.66 |
| Generator Rate for 40’ of power space | | $138.50 |
| Generator Rate for 45’ of power space | | $141.65 |
| Generator Rate for 50’ of power space | | $144.27 |
| Generator Rate for 55’ of power space | | $146.49 |
| Generator Rate for 60’ of power space | | $148.40 |

# OEB STAFF INTERROGATORY # 14

**Reference:**
Exhibit A-2-1

**Interrogatory:**
**Preamble:**
At Exhibit A-2-1, p. 20, the Applicants state:

> All of the above incremental costs will be financed through productivity gains associated with the transaction, will not be included in Hydro One's revenue requirement, and thus will not be funded by ratepayers.

**Questions:**
a) Please state how the Applicants will ensure that the transaction and transition costs will not be included in its ratepayer funded revenue requirement.

b) Please confirm how these costs will be financed if anticipated productivity gains are not fully realized.

**Response:**
a) Hydro One has not included transaction nor transition costs in its current 2018-2022 Distribution Rates Application (EB-2017-0049) and will not include these costs in any future revenue requirements. The Ontario Energy Board, in approving just and reasonable rates under section 78 of the *Ontario Energy Board Act, 1998*, will ensure that these costs are not included as part of Hydro One's future revenue requirement application.

b) In the very unlikely event that the anticipated productivity gains associated with the transaction do not materialize over the 10 year deferral period, then the remaining balance of the $9M[1] transaction and integration costs will be borne by Hydro One shareholders.

[1] Exhibit A, Tab 2, Schedule 1, page 20 (incremental transaction costs of $3M, and integration costs of $6M)

# OEB STAFF INTERROGATORY # 15

**Reference:**

Exhibit A-1-1, Section 5.0 Other Approvals and Considerations
Exhibit A-2-1, Section 3.0 Other Related Matters

**Interrogatory:**

**Preamble:**

Hydro One is applying for approval to continue to track costs in the regulatory asset accounts currently approved by the OEB for OPDC and seek disposition of their balances at a future date.

**Questions:**

a) Does Hydro One have an anticipated timeline in mind for when the IESO settlement processes will be harmonized and Hydro One will receive a single, consolidated monthly IESO invoice that includes OPDC's costs?

b) Please confirm that Hydro One intends to maintain a separate set of Group 1 regulatory deferral and variance accounts (DVAs) for the OPDC rate zone until the next rebasing application and that the balances accumulated in those accounts will be disposed to OPDC customers only.

c) How does Hydro One intend to settle with the IESO during:
   i. The period prior to IESO invoice harmonization?
   ii. The period subsequent to IESO invoice harmonization?

d) For the year in which IESO invoice harmonization takes place, please confirm that Hydro One's intent is to submit disposition requests for the OPDC rate zone's Group 1 DVA balances that accumulated prior to IESO invoice harmonization, as well as a request for the disposition of Group 1 DVA balances that accumulated subsequent to IESO invoice harmonization. If this is not the case, please explain how Hydro One intends to dispose of Group 1 DVA balances for the year in which IESO invoice harmonization occurs.

e) In the event that the IESO invoice is harmonized, but the Group 1 DVAs continue to be maintained separately, how does Hydro One propose to allocate the IESO charges to the respective regulatory accounts of the OPDC rate zone?

Does Hydro One have intentions to request the alignment of the effective rate year of the OPDC rate zone with that of Hydro One's prior to rebasing? If so, when does it expect to do so? If not, why not?

**<u>Response:</u>**

a) IESO Settlement processes will be merged with Hydro One at the completion of the integration process when meter points and customer data are successfully migrated into Hydro One Networks Inc.'s existing IT systems. The integration timeline is anticipated to take between 8-12 months.

b) Confirmed

c)
   i. Upon approval of the MAAD application, and as part of financial closing activities, Hydro One and OPDC will work with the IESO to initiate the IESO's Market Registration process to authorize Hydro One as the metered and registered market participant for OPDC's Distribution License. The IESO on closing will settle with the metered and registered market participant OPDC. No technology changes will be made prior to closing outside of updating registration with the IESO for Hydro One. The existing OPDC metering and customer information systems utilized today will continue to transact with the IESO to support settlements. The existing staff at OPDC that support the process today will continue to operate the process under the established services agreement until the integration date.

   ii. In the period subsequent to IESO invoice harmonization, Hydro One will be settling with the IESO as it does currently via receipt of, reconciliation of, and payment of the IESO invoice. Customer and financial systems will be fully integrated with Hydro One. As of the integration date, the assets will transfer to Hydro One from OPDC and be settled with the IESO by Hydro One consistent with recent LDC integrations performed by Hydro One.

d) On April 27, 2018, the OEB issued a letter to Hydro One indicating that it will be undertaking an audit of Hydro One's RPP settlement process and to assess the allocation methodology Hydro One uses to assign balances for Group 1 deferral and variance accounts for the Acquired Utilities, namely, Haldimand Country Hydro Inc., Norfolk Power Distribution Ltd., and Woodstock Hydro Services Inc. During the inspection, Hydro One proposed a new methodology to allocate RSVA balances to the acquired LDCs based on post-integrated sales volumes. This methodology was reviewed by OEB staff through the RPP Settlement Process and DVA Allocation Methodology audit completed in March 2019. The audit concluded that Hydro One's proposed methodology was reasonable. It is HONI's intention to adopt the approach going forward and apply to all the acquired LDCs including Orillia and Peterborough. Please see attached audit report from OEB for your reference.

e) See part d) above.

Consistent with prior proceedings for the Acquired Utilities (EB-2015-0269, EB-2015-0271 and EB-2017-0259) Hydro One will seek to align the effective date of the rate year for the Orillia service area with that of Hydro One (i.e. January 1st) at the first rates application for the Orillia service area following operational integration with Hydro One.

**Ontario Energy Board**
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416-481-1967
Facsimile: 416-440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie de l'Ontario**
C.P. 2319
27e étage
2300 rue Yonge
Toronto ON M4P 1E4
Téléphone: 416-481-1967
Télécopieur: 416-440-7656
Numéro sans frais: 1-888-632-6273

Ontario

March 4, 2019

Mr. Frank D'Andrea
Vice President, Chief Regulatory Officer, Chief Risk Officer
Hydro One Networks Inc.
South Tower, 8th floor
483 Bay Street
Toronto, ON, M5G 2P5

Dear Mr. D'Andrea:

**Re: Inspection of the Compliance of the RPP Settlement Process and Assessment of the DVA Allocation Methodology for the Acquired Utilities in 2015 and 2016**

The Ontario Energy Board's Audit & Investigations Department (OEB staff) has completed its inspection of Hydro One Networks Inc.'s (HONI) compliance with respect to regulatory requirements for the Regulated Price Plan (RPP) settlement processes and its assessment of the deferral and variance accounts (DVAs) allocation methodology to assign balances for Group 1 DVAs for all acquired utilities in 2015 and 2016. The inspection was initiated due to the magnitude of ratepayer funds involved in HONI's RPP settlement processes and relevant regulatory accounts.

The results of the inspection are now shared with HONI in the form of a written inspection report. To the extent that the inspection required the examination of documents, records or information that are not already in the OEB's possession, OEB staff acted under Part VII of the *Ontario Energy Board Act, 1998* (the Act).

The inspection report concludes that nothing has come to OEB staff's attention indicating that HONI's RPP settlement claim processes are not in compliance with current regulatory requirements. As well, the report confirms that HONI also utilizes a reasonable allocation methodology for Group 1 DVAs for the acquired utilities in 2015 and 2016.

Notwithstanding the prior paragraph, the conclusions contained in the inspection report, as summarized above, are made without prejudice with regard to any future review by OEB staff relating to the refund of $121.8 million received from the IESO related to Charge Type 148[1] for the period of April to November 2017 (as disclosed in HONI's rate application EB-2017-0049) .

The OEB issued a letter on July 20, 2018, advising electricity distributors of the OEB's initiative to standardize the accounting guidance related to commodity pass-through accounts. The OEB provided an initial set of standardized requirements for regulatory accounting and RPP settlements on February 21, 2019 titled *Accounting Guidance related to Accounts 1588 RSVA Power, and 1589 RSVA Global Adjustment*. For some distributors, the result of implementing this guidance may be that changes will be required to their current processes even though the current processes result in accurate balances. HONI is expected to comply with this accounting guidance and to continue comply with all other relevant regulatory requirements.

We thank you for your cooperation and assistance. Please do not hesitate to contact the undersigned directly should you have any questions.

Yours truly,

Tony Stanco
Manager - Audit & Investigations

Copy:
Mr. Chris Lopez, Acting Chief Financial Officer – Chris.Lopez@HydroOne.com

---

[1] Class B – Global Adjustment Settlement Amount

## ONTARIO ENERGY BOARD

Ontario

# Inspection Report

---

## Inspection of the Compliance of the RPP Settlement Process and Assessment of the DVA Allocation Methodology for the Acquired Utilities

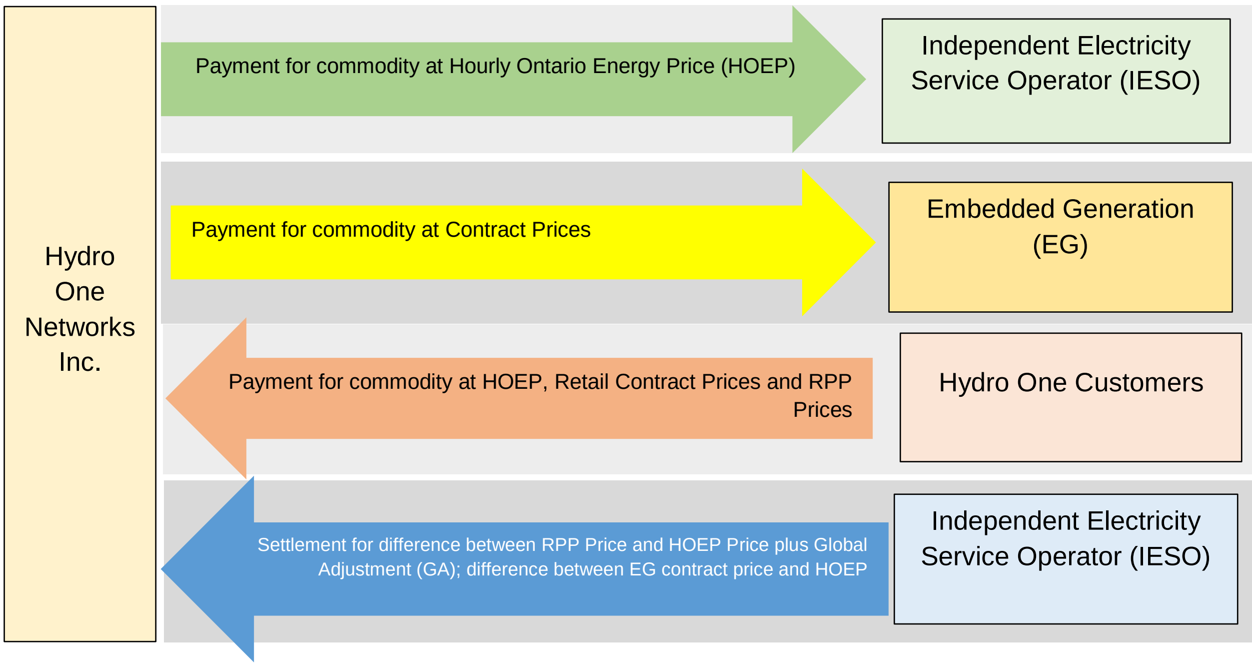
## Hydro One Networks Inc.

**Date: March 4, 2019**

# CONTENTS

## 1. Executive Summary

The Ontario Energy Board (OEB)'s Audit and Investigations Department (Staff) undertook an inspection of Hydro One Networks Inc.'s (HONI) Regulated Price Plan (RPP) Settlement Claim process for the period of January 1 to December 31, 2017. The RPP Settlement Claim process is summarized in the flow diagram below:




This inspection evaluated the compliance of HONI's RPP Settlement Claim process with the established IESO Market Rules and Ontario Regulations as detailed in Appendix 4. In addition, this inspection assessed the reasonability of the allocation methodology for Deferral and Variance Accounts (DVA) for the three acquired utilities by HONI in 2015 and 2016.

Based on the inspection, nothing has come to OEB staff's attention that HONI's RPP Settlement Claim with the IESO is not in compliance with the relevant IESO Market Rules and Ontario Regulations. OEB staff has also concluded on the following:

(1) In EB-2017-0050, HONI described its allocation methodology as using historical pre-integration consumption as the allocator. Subsequently during the inspection, HONI proposed a new allocation methodology which uses post-integration sales volume as the allocator. HONI has demonstrated that after all the acquired utilities are integrated into HONI's financial systems, this proposed RSVA allocation methodology resulted in the same set of rate riders, whether the RSVA balances are allocated to HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro separately, or to all utilities together as one single entity.

(2) Due to the cumulative impact of the energy injected back to the grid (AQEI) on Global Adjustment (GA) for the period of January 2005 to August 2016, HONI received the refund of $121.8 million from the IESO related to CT 148[1] for the period of April to November 2017. HONI first informed the OEB of the $121.8 million refund in the rate application EB-2017-0049. Staff intends to follow up on this matter in the future.

## 2. Reason for Inspection

This inspection was selected based on a risk assessment following the Global Adjustment Policies and Processes Sector Review. The objective of the GA review was to better understand and identify the underlying potential risks within the various processes associated with the quantification of GA amounts or quantum, and the allocation of those amounts for recovery from different customer classes. The result of the review informed the need for the OEB to inspect the RPP Settlement Claims that are submitted by the distributors to the IESO on a monthly basis.

The inspection also assessed the allocation methodology proposed by HONI for the three utilities acquired during 2015 and 2016 (collectively, the acquired utilities).

- Norfolk Power Distribution Inc. (Norfolk Power) – Integrated in September 2015
- Woodstock Hydro Services Inc. (Woodstock Hydro) – Integrated in September 2016
- Haldimand County Hydro Inc. (Haldimand County Hydro) – Integrated in September 2016

On April 5, 2018, the OEB issued a Decision and Rate Order for a rate application EB-2017-0050. Specifically, in relation to Group 1 DVA, the OEB had concerns with certain balances (most notably in Account 1588 – Power for Norfolk Power and Account 1589 – GA for all three of the acquired utilities), mainly resulting from HONI's proposed allocation methodology and the resulting impacts to customers of the three former utilities' rate zones. The OEB noted that while the proposed allocation methodology conceptually appeared reasonable, the OEB believed HONI did not sufficiently explain why the principal transactions in the year of integration for the acquired utilities were substantially higher than in prior years, other than noting that the balances were the result of the proposed allocation methodology. For these reasons, the OEB only approved the disposition of Group 1 DVA balances for each of the acquired utilities up to December 31 of the year prior to their acquisition. For Norfolk Power, the disposition was to the end of December 31, 2014. For Haldimand County Hydro, the disposition was to the end of December 31, 2015, and for Woodstock Hydro the disposition was to the end of December 31, 2015.

[1] Class B – Global Adjustment settlement amount

## 3. Objectives and Scope

The objectives of this inspection were as follows:

1. Evaluate the processes and controls in place to ensure HONI's RPP Settlement Claim process with the IESO complies with the established IESO Market Rules and Ontario Regulations as detailed in Appendix 4.

2. Determine whether the RPP and embedded generation (EG) settlement amounts, including the RPP true-ups are accurate and complete and the settlements are recorded in the appropriate account.

3. Validate that GA charges are properly allocated between Accounts 1588 and 1589.

4. Verify the reasonability of the allocation methodology for Group 1 DVAs for the utilities acquired in 2015 and 2016.

The scope of the inspection was for the period of January 1 to December 31, 2017.

## 4. Methodology

Through the inspection, staff:

- Obtained an understanding of HONI's policies, procedures, and controls with respect to the determination and reporting of the RPP and EG settlement amounts with the IESO and allocation of the settlement amounts to Account 1588 and Account 1589.

- Assessed HONI's compliance with relevant regulations made under the *Ontario Energy Board Act, 1998* and *Electricity Act, 1998*.
  - *Ontario Energy Board Act, 1998,* Ontario Regulation 95/05 Classes of Consumers and Determination of Rates
  - *Electricity Act, 1998,* Ontario Regulation 429/04 Adjustment under Section 25.33 of the Act
  - *Electricity Act, 1998,* Ontario Regulation 430/04 Payments re Section 25.33 of the Act

- Assessed HONI's compliance with the IESO market rules on settlement.

- Assessed the methodology and underlying information (volumes and prices) for the determination of the monthly RPP settlement amounts and true-up amounts.

- Examined HONI's compliance with the relevant sections in the Accounting Procedures Handbook for Electricity Distributors (APH), effective January 1, 2012, for the purpose of Account 1588 and Account 1589.

- Verified through samples of the information submitted on RPP forms and entries to Accounts 1588 and 1589.

- Assessed the process for EG settlement and GA allocations between RPP and non-RPP customers.

- Assessed the reasonability of the allocation methodology for Group 1 DVA accounts for the acquired utilities.

Refer to Appendix 2 for the description of the RPP Settlement Claim Process

Refer to Appendix 3 for the details on the allocation methodology.

Refer to Appendix 4 for the description on the compliance assessment criteria.

## 5. Licensee Profile

HONI is Canada's largest electricity transmission and distribution service provider transmitting and distributing electricity across Ontario. HONI distributes electricity to over 1.3 million residential and business customers covering approximately 75 per cent of the geographic area of Ontario.

## 6. Conclusion

Based on the results of the inspection for the identified areas within the inspection scope, nothing has come to OEB staff's attention that HONI's RPP Settlement Claim with the IESO is not in compliance with the relevant Ontario Regulations. HONI's RPP Settlement Claim process with the IESO satisfies the inspection objectives and HONI has established reasonable allocation methodology for Group 1 DVAs for the acquired utilities.

As well, the findings and conclusions contained in this report are made without prejudice with regard to any future review by OEB staff relating to the refund of $121.8 million as noted in Section 7.1.2.

# 7. Appendix 1 - Detailed Observations

## 7.1.1 RSVA Allocation Methodology

Summary of Observation

In EB-2017-0050, HONI described its allocation methodology as using historical pre-integration consumption as the allocator. Subsequently during the inspection, HONI proposed a new allocation methodology which uses post-integration sales volume as the allocator. HONI has demonstrated that after all the acquired utilities are integrated into HONI's financial systems, this proposed RSVA allocation methodology resulted in the same set of rate riders, whether the RSVA balances are allocated to HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro separately, or to all utilities together as one single entity.

Details of Observation

In EB-2017-0050, HONI described its allocation methodology as using historical pre-integration consumption as the allocator. During the inspection, HONI identified that the existing allocation methodology had not resulted in reasonable balances for the following two reasons:

- The cost allocation is based on three-year historical data which does not factor in customer changes in the post-integration period. As such, any changes to commercial customers may cause the pre-defined allocation factors to be inaccurate; and,

- The newly connected EG is not classified to the corresponding acquired local distribution companies' (LDC) territories. Instead, the newly connected EGs are recognized as part of HONI as a consolidated entity. Therefore, the EG total for the acquired LDCs and the cost allocated to the acquired LDCs may have been understated.

HONI has proposed a new allocation methodology which uses post-integration sales volume as the allocator. Using the sales volume as the allocator is consistent with the methodology from the OEB's CoS DVA Workform Model and IRM Rate Generator Model as was used in previous HONI applications[2]. In addition, the new allocation methodology follows the same principle as the OEB's policy for allocating the GA and the Capacity Based Recovery (CBR) variance balances to customers who transition between Class A and Class B within a given year.

HONI has demonstrated that after all the acquired utilities are integrated into HONI's financial systems (i.e. after the transition years 2015 and 2016), HONI's proposed RSVA allocation methodology resulted in the same set of rate riders, whether the RSVA balances are allocated

[2] E.g. EB-2009-0096 and EB-2013-0416

to HONI Networks, Norfolk Power, Haldimand County Hydro and Woodstock Hydro separately or to all utilities together as one single entity.

Refer to Appendix 3 – Allocation of RSVA Balances in Post-Transition Years which provides detailed walkthroughs of calculations for single and multiple rate riders.

Conclusion and Expectation

HONI's proposed allocation methodology of using applicable sales volume as the allocator for Group 1 Accounts 1588 and 1589 balances for Haldimand County Hydro, Norfolk Power and Woodstock Hydro is reasonable.

In its future rate applications, HONI should submit the balances for the years of integration and the post integration years for each of the three acquired utilities as follows and all the balances to be submitted for disposition must be well supported.

The Group 1 DVA balance for Norfolk Power (integrated with HONI in September 2015), for 2015 will be comprised of 8 months of pre-acquisition balances, plus 4 months of post integration allocated balances using the proposed methodology. For each year starting with 2016, until HONI's next cost of service application which will include harmonizing Norfolk Power Distribution into its rates, HONI should compute 12 months of post integration allocated balances using the proposed methodology. HONI must provide supporting calculations for 2015 and each subsequent year being sought for disposition.

The Group 1 DVA balance for Woodstock Hydro (integrated with HONI in September 2016), for 2016 will be comprised of 8 months of pre-acquisition balances, plus 4 months of post integration allocated balances using the proposed methodology. For each year starting with 2017, until HONI's next cost of service application which will include harmonizing Woodstock Hydro into its rates, HONI should compute 12 months of post integration allocated balances using the proposed methodology. HONI must provide supporting calculations for 2016 and each subsequent year being sought for disposition.

The Group 1 DVA balance for Haldimand County Hydro (integrated with HONI in September 2016), for 2016 will be comprised of 8 months of pre-acquisition balances, plus 4 months of post integration allocated balances using the proposed methodology. For each year starting with 2017, until HONI's next cost of service application which will include harmonizing Haldimand County Hydro into its rates, HONI should compute 12 months of post integration allocated balances using the proposed methodology. HONI must provide supporting calculations for 2016 and each subsequent year being sought for disposition.

### 7.1.2 $121.8M IESO Refund

Summary of Observation

Due to the cumulative impact of the energy injected back to the grid (AQEI) on GA for the period of January 2005 to August 2016, HONI received a refund of $121.8 million from the IESO related to CT 148[3] for the period of April to November 2017. HONI first informed the OEB of the $121.8 million refund in the rate application EB-2017-0049. Audit & Investigations staff intends to follow up on this matter in the future.

Detailed Observation

As explained by HONI, HONI estimated a GA amount to be charged by the IESO for the month end accrual purpose for June 2016. Upon receiving the actual invoice from the IESO in July 2016, HONI noticed a greater than expected GA charge amount. HONI then investigated the GA variance and noticed a trend of deviation from expected GA. The GA variance was determined to be the volume impact of the AQEI as a result of increased number of EG connections. The impact resulted in an overcharge of CT148 for the period of January 2005 to August 2016. Subsequently, IESO refunded the overcharge of $121.8 million through the monthly IESO invoices from April to November 2017 for the impact of the AQEI on GA for the period of January 2005 to August 2016.

Conclusion and Expectation

HONI is expected to reassess the impact of the refund and corresponding charges have on RPP and non-RPP customers and ensure that there are appropriate processes and controls put in place to rectify the overcharges going forward.  The OEB staff intends to follow up on this matter in the future.

[3] Class B – Global Adjustment Settlement Amount

## 8. Appendix 2 – RPP Settlement Claim Process

On a monthly basis, HONI calculates an amount payable/receivable to/from the IESO to settle for the previous month RPP consumption based on invoice issued. Since HONI's customers do not all have a billing cycle that coincides with the calendar month, HONI does not declaring RPP consumption data based on the calendar month consumption. HONI accrues the RPP settlement amount for the portion of the unbilled revenue for accounting purposes at month end along with all other charge types from the IESO invoices on the cost side and unbilled revenue on the revenue side for both accounts 1588 and 1589. HONI's monthly RPP settlement claim includes two amounts:

(1) the difference between the energy amounts billed at RPP price and Spot price for the invoices created during each fiscal month; and,
(2) the RPP invoiced Consumption at actual GA rate.

The RPP settlement amounts, are communicated to the IESO via an online portal on or before the 4th business day of the month and appear under charge type 1142 on the IESO invoice.

The EG and Class A volumes are communicated to the IESO via the online portal on or before the 4th business day of the month and are used by the IESO to calculate the GA and appear under charge types 147 and 148 on the IESO invoice.

HONI extracts billed customer RPP commodity charges (TOU and Tiered) from the GL activity and extracts billed consumption for RPP customers from their Customer Information System (CIS). HONI also determine the WAHSP charges based on billed consumption for RPP customers from its CIS.

The monthly IESO settlements also include the EG declaration for the difference between the rate paid to regulated and contracted generators and spot price. Monthly, embedded distributors (eLDC) calculate their own RPP and generation settlement amounts and declare to the IESO through HONI Distribution. As a host distributor, HONI Distribution settles with the IESO on behalf of embedded distributors and treats it as pass through costs, in the monthly IESO settlement declaration.

HONI is charged by the IESO the actual GA rate in CT 148 on the volumes representing the power withdrawn from the grid plus the EG volume minus the Class A volume on a calendar month basis. As the GA is embedded in the RPP price, the IESO must reimburse HONI for the RPP portion of the GA and reflect it in CT 1142. HONI uses the second estimate of GA rate published by IESO to calculate RPP GA settlement associated with the RPP consumption during the fiscal month. As the actual rate is not available until 10th business day of each month for the preceding month, which is six business days after the utility submits the RPP settlement claim to the IESO on the 4th business day, the true up is calculated by using the actual GA rate and declared to the IESO in the following month.

## 9. Appendix 3 – Allocation of RSVA Balances for the Acquired Utilities

After the transition period (i.e. from September 1, 2016 onwards), HONI's current proposed RSVA allocation methodology will result in the same set of rate riders, whether the RSVA balances are allocated to HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro separately or to all utilities together as one single entity.

Below is an illustrative example created by HONI using RSVA Power (1588) transactions and associated detailed kWh information from HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro during the period September 1st to December 31, 2016 (post transition). The illustrative example compares two allocation scenarios:

1. Allocating the RSVA Power balance to HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro separately first, and then to each utilities' rate classes; and,
2. Allocating the RSVA Power balance to all rate classes assuming that all four utilities are one single entity.

The illustrative example uses the total kWh for each utility over this period because detailed 2017 kWh information (i.e. grouped by WMP/non-WMP/RPP/non-RPP/ClassA/ClassB/LDC/non-LDC by rate class) could not be prepared in the given timeline and is not critical for the purpose of illustrating that the two allocation scenarios will provide the same results.

### Scenario 1: Allocating RSVA Power balance (1588) to each utility separately first, and then to each utilities' rate classes

Table 1 below shows how the RSVA Power balance over the Sep.1 to Dec. 31, 2016 period is allocated to HONI, Norfolk Power, Haldimand County Hydro and Woodstock Hydro by kWh.

**TABLE 1 - RSVA Power $ and kWh**

| | (1) | (2) | (3) | (4) | (5) | (6)=(2)+(3)+(4)+(5) |
|---|---|---|---|---|---|---|
| RSVA Power | Total Principle + Interest* | H1 kWh** | NF kWh** | HC kWh** | WS kWh** | Total kWh** |
| 1588 | ($4,572,422) | 7,584,123,336 | 108,194,087 | 109,303,647 | 135,346,369 | 7,936,967,439 |
| | | | | | | |
| | | (7)=(2)/(6) | (8)=(3)/(6) | (9)=(4)/(6) | (10)=(5)/(6) | |
| | | H1 % of kWh | NF % of kWh | HC % of kWh | WS % of kWh | Total |
| | | 95.6% | 1.4% | 1.4% | 1.7% | 100.0% |
| | | | | | | |
| | | (11)=(1)x(7) | (12)=(1)x(8) | (13)=(1)x(9) | (14)=(1)x(10) | |
| | | Allocated H1 $ | Allocated NF $ | Allocated HC $ | Allocated WS $ | Total |
| | | ($4,369,151) | ($62,330) | ($62,969) | ($77,972) | ($4,572,422) |

* Sept 1 to Dec 31 2016
** Sept 1 to Dec 31 2016 non-WMP kWh

H1: Hydro One Networks
NF: Norfolk Power
HC: Haldimand County Hydro
WS: Woodstock Hydro

The actual kWh by rate class for each utility is not readily available for this period. For comparing the scenarios, an illustrative breakdown of the kWh by rate class is used. Table 2 shows the illustrative kWh by rate class for each of the four utilities used in assessing both scenarios.

**TABLE 2 - Illustrative kWh by rate classes**

| Illustrative H1 kWh and rate classes | | | |
|---|---|---|---|
| (15) | (16) | (17) | (18)=(15)+(16)+(17) |
| H1 rate class 1 kWh | H1 rate class 2 kWh | H1 rate class 3 kWh | Total H1 kWh |
| 5,308,886,335 | 1,516,824,667 | 758,412,334 | 7,584,123,336 |
| | | | |
| (19)=(15)/(18) | (20)=(16)/(18) | (21)=(17)/(18) | |
| % kWh | % kWh | % kWh | |
| 70% | 20% | 10% | |

| Illustrative NF kWh and rate classes | | | |
|---|---|---|---|
| (22) | (23) | | (24)=(22)+(23) |
| NF rate class 1 kWh | NF rate class 2 kWh | | Total NF kWh |
| 70,326,157 | 37,867,931 | | 108,194,087 |
| | | | |
| (25)=(22)/(24) | (26)=(23)/(24) | | |
| % kWh | % kWh | | |
| 65% | 35% | | |

| Illustrative HC kWh and rate classes | | | |
|---|---|---|---|
| (27) | (28) | | (29)=(27)+(28) |
| HC rate class 1 kWh | HC rate class 2 kWh | | Total HC kWh |
| 60,117,006 | 49,186,641 | | 109,303,647 |
| | | | |
| (30)=(27)/(29) | (31)=(28)/(29) | | |
| % kWh | % kWh | | |
| 55% | 45% | | |

| Illustrative WS kWh and rate classes | | | |
|---|---|---|---|
| (32) | (33) | | (34)=(32)+(33) |
| WS rate class 1 kWh | WS rate class 2 kWh | | Total WS kWh |
| 70,380,112 | 64,966,257 | | 135,346,369 |
| | | | |
| (35)=(32)/(34) | (36)=(33)/(34) | | |
| % kWh | % kWh | | |
| 52% | 48% | | |

Table 3 below shows how each utility's allocated RSVA Power balance, as calculated in Table 1, is allocated to its rate classes by kWh.

**TABLE 3 - Allocated $ by rate classes**

| (37)=(11)x(19) | (38)=(11)x(20) | (39)=(11)x(21) | |
|---|---|---|---|
| Allocated H1 rate class 1 $ | Allocated H1 rate class 2 $ | Allocated H1 rate class 3 $ | Total |
| ($3,058,406) | ($873,830) | ($436,915) | ($4,369,151) |

| (40)=(12)x(25) | (41)=(12)x(26) | | |
|---|---|---|---|
| Allocated NF rate class 1 $ | Allocated NF rate class 2 $ | | Total |
| ($40,514) | ($21,815) | | ($62,330) |

| (42)=(13)x(30) | (43)=(13)x(31) | | |
|---|---|---|---|
| Allocated HC rate class 1 $ | Allocated HC rate class 2 $ | | Total |
| ($34,633) | ($28,336) | | ($62,969) |

| (44)=(14)x(35) | (45)=(14)x(36) | | |
|---|---|---|---|
| Allocated WS rate class 1 $ | Allocated WS rate class 2 $ | | Total |
| ($40,545) | ($37,427) | | ($77,972) |

**Scenario 2: Allocating RSVA Power balance (1588) to all rate classes by treating all four utilities as one single entity**

Table 4 below shows how the total RSVA Power balance is allocated to all rate classes assuming all of the rate classes existed within one single entity. The illustrative kWh for each rate class used to allocate the RSVA balances are the same as the kWh in Table 2.

TABLE 4 - RSVA Power $

| | (1) | (46) | (47) | (48) | (49) | (50) | (51) | (52) | (53) | (54) | (55)=sum(46:54) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RSVA Power | Total Principle + Interest* | H1 rate class 1 kWh** | H1 rate class 2 kWh** | H1 rate class 3 kWh** | NF rate class 1 kWh** | NF rate class 2 kWh** | HC rate class 1 kWh** | HC rate class 2 kWh** | WS rate class 1 kWh** | WS rate class 2 kWh** | Total kWh** |
| 1588 | ($4,572,422) | 5,308,886,335 | 1,516,824,667 | 758,412,334 | 70,326,157 | 37,867,931 | 60,117,006 | 49,186,641 | 70,380,112 | 64,966,257 | 7,936,967,439 |
| | | | | | | | | | | | |
| | | (56)=(46)/(55) | (57)=(47)/(55) | (58)=(48)/(55) | (59)=(49)/(55) | (60)=(50)/(55) | (61)=(51)/(55) | (62)=(52)/(55) | (63)=(53)/(55) | (64)=(54)/(55) | |
| | | % of kWh | % of kWh | % of kWh | % of kWh | % of kWh | % of kWh | % of kWh | % of kWh | % of kWh | Total |
| | | 66.9% | 19.1% | 9.6% | 0.9% | 0.5% | 0.8% | 0.6% | 0.9% | 0.8% | 100.0% |
| | | | | | | | | | | | |
| | | (65)=(1)x(56) | (66)=(1)x(57) | (67)=(1)x(58) | (68)=(1)x(59) | (69)=(1)x(60) | (70)=(1)x(61) | (71)=(1)x(62) | (72)=(1)x(63) | (73)=(1)x(64) | |
| | | Allocated H1 rate class 1 $ | Allocated H1 rate class 2 $ | Allocated H1 rate class 3 $ | Allocated NF rate class 1 $ | Allocated NF rate class 2 $ | Allocated HC rate class 1 $ | Allocated HC rate class 2 $ | Allocated WS rate class 1 $ | Allocated WS rate class 2 $ | Total |
| | | ($3,058,406) | ($873,830) | ($436,915) | ($40,514) | ($21,815) | ($34,633) | ($28,336) | ($40,545) | ($37,427) | ($4,572,422) |

* Sept 1 to Dec 31 2016
** Sept 1 to Dec 31 2016 non-WMP kWh

H1: Hydro One Networks
NF: Norfolk Power
HC: Haldimand County Hydro
WS: Woodstock Hydro

**Comparison of the Two Allocation Scenarios**

As illustrated in Table 5, the RSVA Power balance to be collected from each rate class is identical under the two scenarios.

**Table 5. Allocated RSVA Power Balances by Rate Class**

| | Scenario 1 (from Table 3) | Scenario 2 (from Table 4) | Difference |
|---|---|---|---|
| H1 rate class 1 $ | ($3,058,406) | ($3,058,406) | $0 |
| H1 rate class 2 $ | ($873,830) | ($873,830) | $0 |
| H1 rate class 3 $ | ($436,915) | ($436,915) | $0 |
| NF rate class 1 $ | ($40,514) | ($40,514) | $0 |
| NF rate class 2 $ | ($21,815) | ($21,815) | $0 |
| HC rate class 1 $ | ($34,633) | ($34,633) | $0 |
| HC rate class 2 $ | ($28,336) | ($28,336) | $0 |
| WS rate class 1 $ | ($40,545) | ($40,545) | $0 |
| WS rate class 2 $ | ($37,427) | ($37,427) | $0 |

HONI has demonstrated that the allocated RSVA balances by rate class are identical under both scenarios.

Rate riders for each rate class are determined by dividing the RSVA balance by the charge determinant for the rate class.  Since the allocated RSVA balances by rate class are identical in both cases and the charge determinants are identical in both cases, the resulting rate riders will also be identical.

## 10. Appendix 4 – Detailed Criteria

Below is a detailed list of criteria used to assess compliance:

Ontario Regulations made under the *Electricity Act, 1998*.

- Ontario Regulation 429/04 Adjustment under Section 25.33 of the Act (The regulation for GA)
- Ontario Regulation 430/04 Payments re Section 25.33 of the Act (The regulation for RPP settlements)

Ontario Regulations made under the *Ontario Energy Board Act, 1998*

- Ontario Regulation 95/05 Classes of Consumers and Determination of Rates

IESO Market Rule & Guide:

- IESO Market Rule & Manual Library
- IESO Guide to Online Data Submission via the IESO Portal
  - Regulated Price Plan vs. Market Price - Variance for Conventional
  - Regulated Price Plan vs. Market Price - Variance for Smart Meters
  - Regulated Price Plan - Final Variance Settlement Amount
  - Feed-In Tariff Program – LDC
  - Feed-In Tariff Program – Embedded LDC

Accounting Procedures Handbook for Electricity Distributors, effective January 1. 2012:

1. APH Article 490 – Retail Services and Settlement Variances: Power Charges
   - Retail Settlement Variance Account for Power (RSVA Power)
   - Retail Settlement Variance Account for Global Adjustment (RSVA GA)
2. July 2012 APH FAQs, October 2009 APH FAQs and December 2005 APH FAQs

# OEB STAFF INTERROGATORY # 16

**Reference:**
*Handbook to Electricity Distributor and Transmitter Consolidations*

**Interrogatory:**
**Preamble:**
The OEB's *Handbook to Electricity Distributor and Transmitter Consolidations* includes a list of filing requirements. Under the filing requirements, Section 2.2.4, (page 6 of the filing requirements), applicants are asked to "provide pro forma financial statements for each of the parties (or if an amalgamation, the consolidated entity) for the first full year following the completion of the proposed transaction.

**Question:**
a) Please provide pro forma financial statements for Hydro One including those of OPDC, for the first full year following the completion of the proposed transaction.

**Response:**
Hydro One Distribution's 2018 Financial Statements are provided at Exhibit I, Tab 2, Schedule 41, Attachment 1. The size of OPDC operations will not have any material impact on the financial viability of Hydro One. OPDC's asset base represents less than 1% of Hydro One Distribution's assets in 2018 ($44.5M vs. $8.9B). Hydro One does not believe providing pro forma statements would assist the Board and, notwithstanding Section 2.2.4 of the Filing Requirements, it has not been asked to file such statements in applications of a similar nature previously determined by the OEB.

# OEB STAFF INTERROGATORY # 17

**Reference:**

Exhibit A-2-1, page 2 Table 1, page 23
Exhibit A-3-1, page 7 Table 2

**Interrogatory:**

**Preamble:**

Hydro One is requesting approval to utilize US GAAP for accounting purposes in relation to the ongoing business of the former OPDC. OPDC currently uses IFRS for financial accounting purposes. The current distribution rates for the OPDC service territory are underpinned by Modified IFRS (MIFRS) for regulatory accounting purposes and will continue to be during the deferred rebasing period.

**Questions:**

a) Has Hydro One undertaken any studies or reviews of the types of transactions that will be impacted by the accounting standard transition from IFRS to US GAAP in the former OPDC? If so, please list the areas of accounting that are expected to be impacted. If not, please explain why this hasn't been addressed as of yet and when Hydro One expects to undertake such an exercise.

b) Please quantify the estimated impact on OPDC's revenue requirement during the deferred rebasing period as a result of OPDC changing its accounting standards. Specifically, please separate the components of revenue requirement that are expected to be impacted and show how these calculations are derived. To simplify, OEB staff is seeking the total revenue requirement of OPDC under IFRS versus the total revenue requirement of OPDC under US GAAP, by year, from the date that OPDC is initially acquired to the date when OPDC has its rates rebased (when the deferred rebasing period expires).

c) Please explain how Hydro One intends to account for the differences during the deferred rebasing period to ensure that both the rate payers and/or the utility are kept whole for these differences.

d) If Hydro One's intention in part c) above is to request to have an Accounting Order established to track the revenue requirement differences between MIFRS and US

GAAP in the former OPDC service territory as part of this proceeding, please prepare and submit a Draft Accounting Order as an appendix for approval.

e) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in Table 1: Projected Cost Savings - $M of Exhibit A-2-1. For example, if the Status Quo projections of Table 1 are currently presented under US GAAP standards, present these amounts under IFRS. If they are presented under IFRS, please present these amounts under US GAAP.

f) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in the proposed ESM calculation under Table 2: Earnings Sharing Mechanism of Exhibit A-3-1 (particularly, on OM&A, depreciation, financing costs, and taxes). For example, if the ESM projections are currently presented under US GAAP standards, present these amounts under IFRS. If they are presented under IFRS, please present these amounts under US GAAP standards.

g) Generally speaking, does US GAAP allow for the capitalization of more overhead costs then is permitted under IFRS? Please explain.

   i. If so, then please explain how ratepayers will be better off under US GAAP when the ratepayers of OPDC will now be required to pay a return on rate base associated with costs that would not have been capitalized under IFRS.

**Response:**

a) Hydro One assessed areas of USGAAP and IFRS differences, and determined that the only areas that could impact revenue requirement are the potential difference in capitalization policies of the two companies, particularly with respect to capitalization of certain overhead costs and the level of PP&E componentization. Please see response to Exhibit I, Tab 2, Schedule 4 with respect to the potential difference in capitalization policies of the two companies and response to Exhibit I, Tab 2, Schedule 15 with respect to changes in depreciation expense.

b) Please see part a).

c) Please see part a).

d) Based on the response to part a) above Hydro One believes this is not applicable.

e) Please see part a).

f) Please see part a). The ESM model is based on USGAAP accounting and the guaranteed payment to OPDC customers is based on that model's assumptions. Information is not available for Hydro One to satisfy the request of the model or its inputs to be translated into MIFRS.

g) Please see part a).

# OEB STAFF INTERROGATORY # 18

**Reference:**
Attachment 5 (Asset Purchase Agreement)
Exhibit A-3-1, Table 2

**Interrogatory:**
**Preamble:**
As a result of the sale of its shares, OPDC may be subject to certain incremental tax obligations under the Ontario Electricity Act, and may also be required to revalue its assets to fair-market-value (FMV) as of the date this sale is executed.

**Questions:**
a) Please explain if the sale of shares by OPDC will trigger its exit from the Ontario Payment in Lieu of Taxes (PILs) regime? If not, please explain why that is the case.

b) Please provide the expected incremental PILs costs that will be incurred as a result of the sale of shares, including but not limited to, any business transfer taxes, recapture, capital gains, or departure taxes, payable upon completion of the proposed sale.

c) Please explain if, subsequent to the proposed sale of the OPDC shares, Hydro One will be assuming obligation for these incremental PILs costs (such as, but not limited to, payment of a departure tax, if any) incurred by OPDC as a result of the sale of its shares. If not, please explain how such costs are going to be addressed and or excluded from the transaction.

d) If Hydro One is assuming the obligation for incremental PILs costs noted above, please confirm that these incremental PILs costs will not be recovered from ratepayers and how Hydro One will ensure that these costs are not included in rates.

e) Please explain if OPDC will be required to revalue its assets to FMV for tax reporting purposes as a result the sale of its shares to Hydro One? If not, please explain why.

f) Please confirm whether or not Hydro One intends to pass on to ratepayers the additional Capital Cost Allowance (CCA) deductions that will become available to them as a result of the revaluation of OPDC's assets to FMV noted above. If so, what is Hydro One's expectations with respect to how those future tax deductions should be applied in rates?

g) Please confirm whether or not the PILs costs, including but not limited to the departure tax, associated with the sale of shares by OPDC are reflected in Table 2 of Exhibit A-3-1 (Earnings Sharing Mechanism) and provide justification for this treatment.

h) Please confirm whether or not the utilization of the additional CCA deductions from the revaluation of OPDC's assets are reflected in Table 2 of Exhibit A-3-1 (Earnings Sharing Mechanism) and justification for this treatment.

**Response:**

a) The provisions of section 149(1.1) of the Income Tax Act (the "ITA") applies on the date of signing the Share Purchase Agreement ("SPA") (August 15, 2016) by the parties with OPDC leaving the PILs regime on that date and not on date the shares are actually sold (also referred to as the 'closing date").

   In signing the SPA, Hydro One acquired a contingent right to acquire the shares of OPDC. Consequently, subsection 149(1.1) of the ITA applies and OPDC no longer qualifies as a tax-exempt entity pursuant to 149(1) of the ITA. Consequently, OPDC becomes a corporation that is subject to corporate income tax under the ITA on its operating profits.

   Please see the response to Exhibit I, Tab 5, Schedule 3 of EB 2016-0276 dated January 20, 2017 for further information which remains current.

b) OPDC has calculated that incremental PILs costs of $942,000 were incurred as a result of signing the Share Purchase Agreement on August 15, 2016.

c) Departure taxes of $942,000 became payable by OPDC prior to the share acquisition by Hydro One as they were triggered on the signing of the SPA and not on the closing of the share transaction.

   Consequently, the obligation for incremental PILs is an OPDC liability, which will ultimately be absorbed by OPDC's shareholder and will not impact, or be received from the customers of OPDC.

d) Please refer to part (c) above. Hydro One is **not** assuming the obligation for the incremental PILs. It is the intention of OPDC that departure taxes will be paid by OPDC prior to the close of the sale transaction.

e) Confirmed. OPDC was required to revalue its assets to fair market value ("FMV") for tax reporting purposes. As noted in the response to Part a) above, upon the date of signing the Share Purchase Agreement, OPDC was deemed to have disposed of all of its assets, and reacquired them, at FMV for both federal and provincial income tax purposes.

f) The additional CCA deductions as a result of the revaluation of OPDC assets will not be passed on to OPDC or legacy Hydro One ratepayers, or impact them in any way.

The premium paid by Hydro One is not a cost that is recoverable in rates. Consistent with the OEB's MAADs policy, the applicant is given the opportunity to recover the purchase price premium, along with other transaction related costs it might incur, through the realization of synergies and other cost savings arising from the transaction. Based on the regulatory principle that benefits follow costs and given that the transaction does not relate to the provision of utility services, the benefit arising from the deferred tax asset should accrue solely to shareholders.

Please see the response to Exhibit I, Tab 5, Schedule 3 of EB 2016-0276 dated January 20, 2017 for further information which remains current.

g) The PILS costs (i.e. the departure tax) are not reflected in the Earning Sharing Mechanism as outlined in Exhibit A, Tab 3, Schedule 1. As per the response in Part f) above this is not an item that will impact ratepayers of either Hydro One or OPDC.

h) The additional CCA deductions arising from the revaluation of OPDC assets are not reflected in Hydro One's Earning Sharing Mechanism outlined in Exhibit A, Tab 3, Schedule 1. As per the response in Part f) above this is not an item that will impact ratepayers of either Hydro One or OPDC.

# OEB STAFF INTERROGATORY # 19

**Reference:**

Exhibit A-2-1, Table 1 Projected Costs Savings; Page 19 Incremental Transaction and Integration Costs

**Interrogatory:**

**Questions:**

a) Please provide a more detailed breakdown for how the Status Quo Forecast and Hydro One Forecast was quantified in Table 1 of Exhibit A-2-1, showing the supporting calculations for the differences in OM&A and capital under both scenarios, as well as any key assumptions or figures used in those calculations.

    i. Please ensure that the more detailed Exhibit A-2-1 Table 1 requested in part a) above also separately presents the timeline and any underlying calculations supporting the incremental transaction costs ($0.2M) and integration costs ($9.0M).

**Response:**

a) Exhibit A, Tab 2, Schedule 1 Table 1 provides a comparison of OPDC's operations as a stand-alone distribution company relative to the costs of operating OPDC's service territory once it is integrated within Hydro One. Please refer to Attachments 1 and 2 of this response for the detailed calculation of Projected Savings summarized in Exhibit A, Tab 2, Schedule 1, Table 1.

   Hydro One's projections regarding the integrated service territory are based on its overall, provincial distribution operations which utilize an Asset Risk Assessment (ARA) process. The Hydro One ARA process encompasses the assessment of a multitude of applicable asset categories. In the OPDC integration case, Hydro One examined the functions outlined below:

   - Vegetation Management
   - Lines Maintenance and Refurbishment
   - Demand Work
   - Wood Pole Replacement
   - Stations

- Environment
- Other Sustainment
- Customer Connections / Upgrades
- System Reinforcement
- Distributed Generation
- Other Development

Field assessment and visual inspections and evaluations were completed and asset information was collected on existing OPDC assets such as asset age, number of assets, asset condition, etc. Utilizing this data, renewal and maintenance costing based on Hydro One's strategies for all Hydro One assets was applied to determine asset needs going forward for maintenance and capital funding. This process was used to provide an estimate of the overall level of spending required to serve the existing OPDC service territory, as provided in Exhibit A, Tab 2, Schedule 1. The aggregate spend was then compared to OPDC's forecast aggregate spend over the same 10-year period to project the net annual savings.

Hydro One's ARA process is further described in Exhibit B1, Tab 1, Schedule 1 of EB-2017-0049 DSP Section 2.1. The ARA process is relied upon by Hydro One for its ongoing operations throughout the province in respect of developing operating and maintenance cost expectations and schedules for all existing assets.

For OPDC's forecast, please refer to Attachments 3 and 4 of this response for the detailed calculation of Status Quo summarized in Exhibit A, Tab 2, Schedule 1, Table 1.

Attachment 3 describes OPDC's operations, maintenance and administration expenditures in more detail related to the ten years presented in Table 1. Total OM&A expenditures are expected to increase 2% annually over the forecast timeframe.

Attachment 4 describes OPDC's capital expenditures (net of contributed capital) in more detail related to the ten years presented in Table 1. Capital expenditures for years 2020 to 2023 are based on OPDC's latest five-year business plan. For the purposes of forecasting the balance of the full ten-year period, for which OPDC does not have a detailed capital business plan, the approach taken was to estimate OPDC's capital expenditure needs at the 'total' envelope' level.

Total capital spending forecast for the 2024 - 2029 period was based on the average of the projected spending for the business plan period 2020 – 2023 inflated by 2% then rounded to the nearest $100k. The only exception to that is in year 9 where it is expected that an additional $8M will be required to build a new service centre under the status quo option.

i) The Table 1 projected savings exclude incremental transaction and integration costs as these costs are incurred by the shareholder to complete the transaction and will not be part of the ongoing costs incurred to operate the OPDC business. Exhibit A, Tab 2, Schedule 1 Table 1, represents Hydro One's forecast ongoing cost to serve the customers of OPDC.

Exhibit I, Tab 3, Schedule 6 part a) Table 1 provides a timeline of incremental transaction and integration costs that are in addition to the costs found in Exhibit A, Tab 2, Schedule 1, Table 1.

Hydro One notes that the question references incorrect dollar amounts – correct values from Exhibit A, Tab 2, Schedule 1 page 20 are as follows: incremental transaction costs (~$3M) and integration costs (~$6M).

# Attachment 1
# Exhibit A, Tab 1, Schedule 2, Table 1 Calculation Assumptions

## General

- This document supplements the Table 1 calculations provided as Exhibit I, Tab 1, Schedule 19, Attachment 2.
- Year 1 in Table 1 represents a 12 month period post-closing of the transaction. This period is assumed to most closely align with calendar year 2020.

## Status Quo Forecast

- Status Quo Forecast represents the continued operation of OPDC as a stand-alone utility (i.e. no transaction scenario)
- Costs are captured as forecast by OPDC in the categories of OM&A and capital expenditures

## Hydro One Forecast

- Hydro One Forecast represents the incremental cost of Hydro One operating and maintaining an integrated OPDC service territory (i.e. contemplated transaction scenario)
- Inflation factor: ~2% per annum
- Customer growth based on Hydro One's assessment: ~1% per annum
- Full operational integration occurs 7 months post financial close (i.e. part way through Year 1)
- OPDC operations centre leased for three years
- Costs are primarily captured in the broad categories of operations, customer care and capital expenditures

# Attachment 2
# Exhibit A, Tab 1, Schedule 2, Table 1 Calculations

## Summary: Orillia Projected Cost Savings

| $M | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A** | | | | | | | | | | |
| Status Quo Forecast | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 | 6.6 |
| Hydro One Forecast | 4.1 | 2.0 | 2.1 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 |
| Projected Savings | 1.5 | 3.6 | 3.7 | 4.2 | 4.3 | 4.4 | 4.5 | 4.6 | 4.6 | 4.7 |
| **Capital** | | | | | | | | | | |
| Status Quo Forecast | 3.2 | 4.3 | 1.5 | 1.8 | 2.8 | 2.8 | 2.9 | 3.0 | 11.1 | 3.2 |
| Hydro One Forecast | 3.4 | 2.4 | 2.4 | 2.5 | 2.6 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 |
| Projected Savings | (0.2) | 1.9 | (1.0) | (0.8) | 0.2 | 0.0 | 0.1 | 0.2 | 8.2 | 0.2 |

## Rounded Summary for Exhibit A, Tab 2, Schedule 1 Table 1

| $M | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A** | | | | | | | | | | |
| Status Quo Forecast | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 | 6.6 |
| Hydro One Forecast | 4.1 | 2.0 | 2.1 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 |
| Projected Savings | 1.4 | 3.7 | 3.7 | 4.2 | 4.3 | 4.4 | 4.4 | 4.6 | 4.7 | 4.7 |
| **Capital** | | | | | | | | | | |
| Status Quo Forecast | 3.2 | 4.3 | 1.5 | 1.8 | 2.8 | 2.8 | 2.9 | 3.0 | 11.1 | 3.2 |
| Hydro One Forecast | 3.4 | 2.4 | 2.4 | 2.5 | 2.6 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 |
| Projected Savings | (0.2) | 1.9 | (0.9) | (0.7) | 0.2 | 0.0 | 0.1 | 0.1 | 8.2 | 0.2 |

## Hydro One Forecast

| | 2020<br>**Year 1** | 2021<br>**Year 2** | 2022<br>**Year 3** | 2023<br>**Year 4** | 2024<br>**Year 5** | 2025<br>**Year 6** | 2026<br>**Year 7** | 2027<br>**Year 8** | 2028<br>**Year 9** | 2029<br>**Year 10** |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A Expenditures** | | | | | | | | | | |
| Operations | 571 | 729 | 750 | 772 | 795 | 818 | 843 | 867 | 893 | 919 |
| Customer Care | 325 | 782 | 793 | 806 | 817 | 829 | 841 | 852 | 864 | 876 |
| Other Not Captured Above | 199 | 75 | 77 | 79 | 80 | 82 | 83 | 85 | 87 | 88 |
| Lease of Orillia HQ | 416 | 423 | 431 | | | | | | | |
| Stand Alone LDC (7 mths) | 2,557 | | | | | | | | | |
| **Total OM&A** | **4,068** | **2,009** | **2,051** | **1,657** | **1,692** | **1,729** | **1,767** | **1,805** | **1,844** | **1,883** |
| **Capital Expenditures** | | | | | | | | | | |
| Capital | 1,305 | 2,368 | 2,436 | 2,507 | 2,579 | 2,796 | 2,790 | 2,857 | 2,926 | 2,997 |
| Stand Alone LDC (7 mths) | 2,070 | | | | | | | | | |
| **Total Operations Capital** | **3,375** | **2,368** | **2,436** | **2,507** | **2,579** | **2,796** | **2,790** | **2,857** | **2,926** | **2,997** |

## Status Quo OM&A Derivation

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| OM&A ($) | 5,542,000 | 5,654,000 | 5,768,000 | 5,883,000 | 6,000,000 | 6,120,000 | 6,243,000 | 6,367,000 | 6,493,000 | 6,621,000 |

| Status Quo OM&A Forecast | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 5,542 | 5,654 | 5,768 | 5,883 | 6,000 | 6,120 | 6,243 | 6,367 | 6,493 | 6,621 |

## Status Quo Capital Derivation

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| CAPITAL (NET of Contributed Capital) ($) | 3,213,000 | 4,309,000 | 1,461,000 | 1,755,000 | 2,750,000 | 2,840,000 | 2,930,000 | 3,020,000 | 11,110,000 | 3,200,000 |

| Status Quo Capital Forecast | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| | 3,213 | 4,309 | 1,461 | 1,755 | 2,750 | 2,840 | 2,930 | 3,020 | 11,110 | 3,200 |

| OPDC - EB-2018-0270 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| | YR 1 | YR 2 | YR 3 | YR 4 | YR 5 | YR 6 | YR 7 | YR 8 | YR 9 | YR 10 |
| **OPERATIONS, MAINTENANCE & ADMINISTRATION EXPENDITURES BREAKDOWN - STATUS QUO** | | | | | | | | | | |
| Operations and maintenance | 1,400,000 | 1,429,000 | 1,457,000 | 1,486,000 | 1,516,000 | 1,547,000 | 1,579,000 | 1,610,000 | 1,642,000 | 1,675,000 |
| Supervision & engineering | 565,000 | 576,000 | 588,000 | 600,000 | 612,000 | 624,000 | 636,000 | 649,000 | 662,000 | 675,000 |
| Control centre | 400,000 | 408,000 | 416,000 | 424,000 | 432,000 | 441,000 | 450,000 | 459,000 | 468,000 | 477,000 |
| Service centre | 312,000 | 318,000 | 324,000 | 330,000 | 337,000 | 344,000 | 351,000 | 358,000 | 365,000 | 372,000 |
| Billing and collections | 1,275,000 | 1,301,000 | 1,328,000 | 1,355,000 | 1,382,000 | 1,409,000 | 1,437,000 | 1,466,000 | 1,495,000 | 1,524,000 |
| Regulatory | 429,000 | 438,000 | 447,000 | 456,000 | 465,000 | 474,000 | 483,000 | 492,000 | 501,000 | 511,000 |
| Administration & general | 1,161,000 | 1,184,000 | 1,208,000 | 1,232,000 | 1,256,000 | 1,281,000 | 1,307,000 | 1,333,000 | 1,360,000 | 1,387,000 |
| **OM&A EXPENDITURES TOTAL - :** | **5,542,000** | **5,654,000** | **5,768,000** | **5,883,000** | **6,000,000** | **6,120,000** | **6,243,000** | **6,367,000** | **6,493,000** | **6,621,000** |
| Percentage increase (decrease) | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |

| OPDC - EB-2018-0270 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|
| | YR 1 | YR 2 | YR 3 | YR 4 | YR 5 | YR 6 | YR 7 | YR 8 | YR 9 | YR 10 |
| **CAPITAL EXPENDITURES BREAKDOWN - STATUS QUO** | | | | | | | | | | |
| Service centre | 10,000 | 10,000 | 10,000 | 10,000 | | | | | 8,000,000 | |
| Substations | | 2,800,000 | | 100,000 | | | | | | |
| Poles & wires | 2,177,000 | 1,295,000 | 1,391,000 | 1,646,000 | | | | | | |
| Meters | 383,000 | 163,000 | 33,000 | 33,000 | | | | | | |
| Heavy Vehicles | 690,000 | | | | | | | | | |
| Light vehicles | 80,000 | 80,000 | 75,000 | 40,000 | | | | | | |
| Other capital assets | 91,000 | 91,000 | 91,000 | 91,000 | | | | | | |
| To be determined | | | | | 2,900,000 | 3,000,000 | 3,100,000 | 3,200,000 | 3,300,000 | 3,400,000 |
| **GROSS CAPITAL EXPEI** | **3,431,000** | **4,439,000** | **1,600,000** | **1,920,000** | **2,900,000** | **3,000,000** | **3,100,000** | **3,200,000** | **11,300,000** | **3,400,000** |
| Contributed capital (defer | **218,000** | **130,000** | **139,000** | **165,000** | **150,000** | **160,000** | **170,000** | **180,000** | **190,000** | **200,000** |
| **NET CAPITAL EXPENDI** | **3,213,000** | **4,309,000** | **1,461,000** | **1,755,000** | **2,750,000** | **2,840,000** | **2,930,000** | **3,020,000** | **11,110,000** | **3,200,000** |
| Percentage increase (c | -36.2% | 34.1% | -66.1% | 20.1% | 56.7% | 3.3% | 3.2% | 3.1% | 267.9% | -71.2% |

# OEB STAFF INTERROGATORY # 20

**Reference:**
Exhibit A-3-1, Table 1; Table 2
Exhibit A-2-1, Table 1

**Interrogatory:**
**Preamble:**
Hydro One has proposed to adjust the forecast OM&A expenses by a risk factor of 20% to account for the fact that it is assuming all operational risks during the 10-year deferred rebasing period, including:

- The risk that the OM&A forecast is not achieved
- The risk that assets are not in the condition anticipated
- The risk that the anticipated load and customer load profiles do not materialize

**Questions:**
a) Please confirm that the OM&A and capital expenditure forecast in Table 1 of Exhibit A-2-1 represents the best estimate of Hydro One's costs and savings during the deferred rebasing period.

b) Please confirm that, under the currently proposed ESM mechanism, Hydro One's shareholders will accrue the potential benefits of:

- The OM&A forecast used being overstated
- The assets being in better condition than anticipated
- The anticipated load and customer load profiles used resulting in a revenue forecast that is understated.

c) Please comment on the appropriateness of an asymmetrical risk-based adjustment to earnings sharing if, presuming the forecast represents the best estimate of future OM&A and capital expenditures, Hydro One's shareholders also accrue the potential benefits of any favourable variances in the assumptions used in the ESM calculation.

d) Please present the amounts in Table 2 of Exhibit A-3-1 on the basis that no risk factor adjustment is applied to the ESM calculation.

**Response:**

a) Confirmed.

b) Hydro One's shareholder is accepting both the potential benefits outlined in this sub-question of the interrogatory and the risks documented in the preamble of the same question, i.e., the risk that the OM&A forecast is not achieved, the risk that assets are not in the condition anticipated and the risk that the anticipated load and customer load profiles do not materialize. All of the risks of attaining the synergy savings as outlined in the application as well as all other economics risks (inflation, tax changes, union salary adjustments) are being assumed by Hydro One's shareholders. The customers of OPDC hold absolutely no risk with Hydro One's proposed ESM, if approved as filed.

Hydro One is absorbing all of the risk of attaining the savings as provided in Exhibit A, Tab 3, Schedule 1 – the ratepayers of OPDC will get this refund. Hydro One is highly incented to maximize savings which ultimately benefits future rates.

c) As noted in the interrogatory, the forecast represents the best estimate of future OM&A and capital expenditures. The pre-calculated ESM guarantees a $3.2M return to the ratepayers of the current OPDC regardless of actual costs incurred. Additionally, as documented in Exhibit A, Tab 3, Schedule 1, the OM&A costs utilized in the ESM calculation will be incremental costs only, e.g., it will not include corporate overheads to the benefit of OPDC ratepayers.

Hydro One believes its proposed ESM approach will help maximize efficiencies and synergies that result from the transaction to the benefit of all ratepayers of the consolidating entities and in so doing, achieve the objective of protecting consumer interests during the extended deferred rebasing period.

Please refer to part b) for the documentation of additional risks being absorbed by Hydro One in an effort to guarantee the ESM.

d) Hydro One's proposed guaranteed ESM, is guaranteed based upon the parameters as set out in Exhibit A, Tab 3, Schedule 1. If the intent of the question is to remove the risk factor, the ESM as proposed will no longer be offered. Hydro One would then seek to track and/or estimate costs to serve OPDC's customers and create a form of Financial Statements to calculate overearnings in years 6 to 10. Hydro One would expect performing this task would result in greater OM&A costs. This could potentially result in lower overearnings, compared to the current ESM, over years 6 to 10 and therefore a lower refund to OPDC's customers. Hydro One notes that any Financial Statements used to calculate the ESM would be unaudited as OPDC would not be a separate financial company.

Please see part b) of this response for further information on the cost savings included in Hydro One's proposed ESM as compared to the costs savings forecast by other MAAD applications which the OEB has approved.

**Table 2: Earning Sharing Mechanism Sharing - Years 6 to 10 ($000's)**
**(No OM&A Risk Factor Applied)**

| | Deferral Period Year | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|
| | **Calendar Year** | **2025** | **2026** | **2027** | **2028** | **2029** |
| 1 | Rate Base | 47,836 | 49,451 | 51,183 | 52,941 | 54,665 |
| 2 | Equity Component of Rate Base | 19,134 | 19,780 | 20,473 | 21,176 | 21,866 |
| 3 | Revenue | 9,310 | 9,515 | 9,725 | 9,946 | 10,158 |
| 4 | OM&A[1] | 1,729 | 1,767 | 1,805 | 1,844 | 1,883 |
| 5 | Depreciation | 1,442 | 1,211 | 1,274 | 1,340 | 1,408 |
| 6 | Interest | 1,700 | 1,757 | 1,819 | 1,881 | 1,942 |
| 7 | Tax | 887 | 908 | 928 | 951 | 971 |
| **8** | **Net Profit After Tax** | **$3,552** | **$3,873** | **$3,899** | **$3,930** | **$3,953** |
| 9 | Achieved ROE (%) (Line 8 ÷ Line 2) | 18.57% | 19.58% | 19.05% | 18.56% | 18.08% |
| 10 | Less: Approved ROE% for OPDC | (9.85%) | (9.85%) | (9.85%) | (9.85%) | (9.85%) |
| 11 | ROE% above Approved ROE% | 8.72% | 9.73% | 9.20% | 8.71% | 8.23% |
| 12 | Less: 300 Basis Points Threshold | (3.00%) | (3.00%) | (3.00%) | (3.00%) | (3.00%) |
| 13 | Total Over-Earnings (%) | 5.72% | 6.73% | 6.20% | 5.71% | 5.23% |
| 14 | Total Over-Earnings (Line 13 x Line 2) | $1,094 | $1,331 | $1,269 | $1,209 | $1,143 |
| 15 | 50% of Overearnings Shared with to OPDC customers | $547 | $666 | $634 | $604 | $572 |
| 16 | Tax Effected Earnings Sharing (26.5%) | $744 | $906 | $863 | $822 | $778 |
| 17 | Cumulative Tax Effected Earnings Sharing (Years 6 to 10) | | | | | **$4,112** |

[1] Risk factor adjustment removed

# OEB STAFF INTERROGATORY # 21

**Reference:**

Exhibit A-3-1, Table 1 (ESM Components); Table 2 (ESM)

**Interrogatory:**

**Questions:**

a) In Table 1, Hydro One has indicated that the starting point for calculating OPDC's forecast rate base was OPDC's 2017 audited Financial Statements.

   Please update the starting point for calculating OPDC's forecast rate base using OPDC's 2018 audited financial statements.

b) Please provide summary continuity schedules, beginning with the most recently available actual fiscal year (OPDCs 2018 audited financial statements), for each of the components presented in lines 1 to 7 of Table 2 of Exhibit A-3-1. Please ensure all key underlying assumptions are disclosed and supporting calculations are provided that were used in deriving these projections. Please include, at a minimum, the following information for each ESM component to support its associated summary schedule(s):

   i. Rate Base: segregate the Property, Plant and Equipment (PP&E), capital contributions, and working capital components in the continuity schedule and explain the methodology behind the growth rates applied to each component

   ii. Revenue: indicate the inflation rate used, the growth rate used for customer load, and any key assumptions made in changes to the forecasted customer load profiles.

   iii. Depreciation: provide the weighted average depreciation rates (or by asset class if practicable) applied to PP&E each year, the average remaining useful lives (or by asset class if practicable) of PP&E each year, and any key assumptions made or processes undertaken by Hydro One to determine the remaining useful lives of the acquired assets.

iv. Financing Costs: disclose the current cost of short-term and long-term debt for Hydro One.

v. Taxes: provide a reconciliation between the combined provincial and federal statutory tax rates (26.5%) and the actual effective tax rates used.

**Response:**

a) Please find at Attachment 1 to this Schedule, Hydro One's ESM model, in working excel format, updated as requested using actual rate base values from OPDC's 2018 audited financial statements. Hydro One is providing this version of its ESM Model in excel format to satisfy OEB Staff's specific request in part a). However, this scenario is not the one reflected in Hydro One's ESM Model that underpins the proposed guaranteed ESM sharing payment to OPDC customers. Hydro One has filed the ESM model that underpins the guaranteed sharing payment in Exhibit I, Tab 2, Schedule 13, Attachment 1.

b)

i. Rate base is calculated by started with end of year asset values from OPDC's 2018 audited financial statements. Hydro One's ESM model (Attachment 1 to this Schedule) on Tab "ESM Model", shows the calculations to support net fixed assets and the "Working Capital" tab provides the assumptions to determine working capital. OPDC's 2018 financial statements are provided at Attachment 1 to Exhibit I, Tab 4, Schedule 4.

ii. The Load and Customer growth assumptions underpinning the annual revenue forecast used in Hydro One's ESM model as found on Tab "ESM Model" at row 47, are consistent with those provided in Exhibit I, Tab 5, Schedule 18 Attachments 1 and 2.

The depreciation rates used for each asset category Hydro One uses in the ESM model are found in Hydro One's ESM model (Attachment 1 to this Schedule) on Tab "Depreciation Rates". The deprecation rates used in Hydro One's ESM model reflect those approved in Hydro One Distribution's recent 2018 to 2022 Rates Application (EB-2017-0049).

Hydro One undertook a high level estimation process for determining the useful lives of OPDC's PP&E. Given the tools available to it (e.g., visual drive-by inspections by field staff and a desktop analysis of asset profiles) Hydro One assessed the average system condition and useful remaining life, on average, to be approximately equal to Hydro One's distribution system's average useful remaining life. As such, for the assets Hydro One plans to acquire from OPDC, Hydro One used its applicable deprecation rates, blended for the asset categories used in the ESM model.

These deprecation rates are considered the most appropriate considering the assumption that after close of the transaction, OPDC's assets and service territory will be integrated into Hydro One. As such, OPDC assets acquired will go into the applicable Hydro One asset category, and attract the Hydro One depreciation rates.

iii. The annual short-term and long-term debt costs for this scenario are found in Hydro One's ESM model (Attachment 1 to this Schedule) on Tab "ESM Model".

iv. The detailed tax workings for this scenario are found in Hydro One's ESM model (Attachment 1 to this Schedule) on Tab "ESM Model".

# SEC INTERROGATORY # 1

**Reference:**
[Ex. A/1/1, p. 3, Ex. A, Attachment 12, Note 14, and EB-2016-0276, Ex. I/5/3]

**Interrogatory:**
With respect to the tax implications of the proposed transaction:

a. Please confirm that, except as set forth in the subsequent sections of this interrogatory, the Applicant's response to SEC Interrogatory #3 in EB-2016-0276 remains correct.

b. Please confirm that OPDC paid a departure tax effective August 14, 2016 of $1,065,000 with respect to the deemed disposition of its assets at fair market value. Please provide the full calculation of that departure tax.

c. Please confirm that approximately $1,065,000 of the purchase price for OPDC reflects the departure tax payable by OPDC prior to acquisition by Hydro One. Please provide a reference in the agreement, or other corroboratory evidence, to support the tax component of the purchase price.

d. Please confirm that, effective August 15, 2016, OPDC acquired a deferred tax asset of $2,214,000 due to its entry into the federal income tax regime. Please provide the full calculation of that deferred tax asset, and reconcile it with the departure tax calculation.

e. Please confirm that, as a result of that fair market value bump, OPDC's federal and Ontario income taxes will be reduced by approximately $300,000 per year until the said deferred tax asset reaches zero. Please provide a schedule showing the forecast application of that deferred tax asset to tax liabilities in 2016 and any subsequent year, on a year by year basis, with all supporting calculations.

**Response:**

a) Confirmed.

b) Hydro One is advised by OPDC that the value referred to in the question above has been updated for new information since the original accrual related to the departure tax liability as outlined in Note 14 of OPDC's 2016 financial statements. Please see Note 11 to OPDC's 2018 financial statements that discloses the estimate of applicable taxes from income and losses including the impact of the deemed disposition (departure taxes) payable to the Ministry of Finance to be $1,141,000. Of that amount, as at December 31, 2018, OPDC has accrued $942,000[1] with respect to the deemed disposition of its assets at fair market value.

OPDC has not as yet paid the departure tax. The accrual remains recorded as a current liability on its balance sheet.

c) OPDC can confirm that $942,000 is payable by OPDC prior to acquisition by Hydro One as departure taxes which became liable upon signing of the Share Purchase Agreement ("SPA").

The SPA has certain purchase price adjustments including an adjustment for working capital changes (SPA reference 2.4 (a) (i)). An increase in taxes payable caused by departure taxes would decrease closing working capital and when compared to initial working capital would reduce the ultimate total price paid for the shares of the utility.

d) The estimated deferred tax asset ("DTA") for goodwill, as per OPDC's 2016 financial statements was $2,214,000[2]. With additional information obtained during 2017 and 2018 aiding the further refinement of the departure tax calculations, the estimate for goodwill was revised to the amount shown in Table 1 below of $13,651,000. Had the identical information been available in 2016 the deferred tax asset reflected would have been $2,641,000 as shown in Table 2 below. As at year-end 2018, OPDC

---

[1] Calculated as the 2016 estimated departure taxes of $1,065k, less decreases in the estimated balance occurring in 2017 of $73k, and 2018 of $50k, totaling a decrease of $123k as disclosed in Note 11 to OPDC's financial statements on page 26.
[2] Note 14 to OPDC's 2016 financial statements, Page 32

estimated the DTA balance related to the goodwill recognized as a result of OPDC's departure from the PILS regime to be $2,284,000[3].

With respect to the deemed disposition of its assets at fair market value, at the date of departure, the amount of goodwill was determined to be $13,651,000. The deferred tax asset related to that goodwill at the deemed departure date was $2,713,000, calculated in Table 1 below as follows;

**Table 1**
**Deferred Tax Asset Related to Goodwill calculated at the Deemed Departure Date ($000's)**

| | |
|---|---|
| Goodwill recognized by OPDC | $13,651 |
| Multiplied by the Deduction allowance (%) | x 75% |
| Balance on which the CCA deduction is calculated | 10,238 |
| Multiplied by the Nominal tax rate (5) (combined provincial and federal tax rates) | x 26.5% |
| Balance of OPDC's Deferred Tax Asset Related to Goodwill | **$2,713** |

e) OPDC cannot confirm that taxes will be reduced by $300,000 per year. Based on results from August 16, 2016 until December 31, 2018, OPDC has been able to claim $1,619,000 in capital cost allowance ("CCA") related to the goodwill component. At an effective tax rate of 26.5% this has resulted in taxes saved of $429,000 over the last three tax returns since leaving the PILs regime.

Based on the 2018 claim alone for CCA related to the goodwill component, OPDC saved $172,000 in taxes for that particular taxation year. CCA for class 14.1 is deductible on a declining balance basis at 7% maximum for the first ten year transitional period and 5% thereafter.

[3] Note 11 to OPDC's 2018 financial statements, Page 27

Assuming the full deduction is taken for goodwill CCA, the most tax reduced going forward related to this item for 2019 would be $160,000. In 2020 the amount of the reduction would be $149,000 with each consecutive year thereafter providing less annual tax reductions. The schedule below illustrates potential reductions spanning to the year 2040. The CCA class is calculated using the declining balance method and as shown below, it will take many years before all of the tax related reductions related to the recognition for goodwill are realized.

**Table 2**
**Illustrative Example - Amortisation of ODPC's Goodwill Deferred Tax Asset (up to 2040)**

| YEAR | OPENING UCC | RATE CLASS 14.1 - ECE | CCA TAKEN | TAXES REDUCED @ 26.5% | CLOSING UCC | DEFERRED TAX ASSET AT 26.5% |
|---|---|---|---|---|---|---|
| 15-Aug-16 | 10,238,000 | **0%** | - | - | 10,238,000 | **2,713,000** |
| 2016 | 10,238,000 | **7%** | 272,000 | 72,000 | 9,966,000 | 2,641,000 |
| 2017 | 9,966,000 | **7%** | 698,000 | 185,000 | 9,268,000 | 2,456,000 |
| 2018 | 9,268,000 | **7%** | 649,000 | 172,000 | 8,619,000 | **2,284,000** |
| 2019 | 8,619,000 | **7%** | 603,000 | 160,000 | 8,016,000 | 2,124,000 |
| 2020 | 8,016,000 | **7%** | 561,000 | 149,000 | 7,455,000 | 1,976,000 |
| 2021 | 7,455,000 | **7%** | 522,000 | 138,000 | 6,933,000 | 1,837,000 |
| 2022 | 6,933,000 | **7%** | 485,000 | 129,000 | 6,448,000 | 1,709,000 |
| 2023 | 6,448,000 | **7%** | 451,000 | 120,000 | 5,997,000 | 1,589,000 |
| 2024 | 5,997,000 | **7%** | 420,000 | 111,000 | 5,577,000 | 1,478,000 |
| 2025 | 5,577,000 | **7%** | 390,000 | 103,000 | 5,187,000 | 1,375,000 |
| 2026 | 5,187,000 | **7%** | 363,000 | 96,000 | 4,824,000 | 1,278,000 |
| 2027 | 4,824,000 | **5%** | 241,000 | 64,000 | 4,583,000 | 1,214,000 |
| 2028 | 4,583,000 | **5%** | 229,000 | 61,000 | 4,354,000 | 1,154,000 |
| 2029 | 4,354,000 | **5%** | 218,000 | 58,000 | 4,136,000 | 1,096,000 |
| 2030 | 4,136,000 | **5%** | 207,000 | 55,000 | 3,929,000 | 1,041,000 |
| 2031 | 3,929,000 | **5%** | 196,000 | 52,000 | 3,733,000 | 989,000 |
| 2032 | 3,733,000 | **5%** | 187,000 | 50,000 | 3,546,000 | 940,000 |
| 2033 | 3,546,000 | **5%** | 177,000 | 47,000 | 3,369,000 | 893,000 |
| 2034 | 3,369,000 | **5%** | 168,000 | 45,000 | 3,201,000 | 848,000 |
| 2035 | 3,201,000 | **5%** | 160,000 | 42,000 | 3,041,000 | 806,000 |
| 2036 | 3,041,000 | **5%** | 152,000 | 40,000 | 2,889,000 | 766,000 |
| 2037 | 2,889,000 | **5%** | 144,000 | 38,000 | 2,745,000 | 727,000 |
| 2038 | 2,745,000 | **5%** | 137,000 | 36,000 | 2,608,000 | 691,000 |
| 2039 | 2,608,000 | **5%** | 130,000 | 34,000 | 2,478,000 | 657,000 |
| 2040 | 2,478,000 | **5%** | 124,000 | 33,000 | 2,354,000 | 624,000 |

# SEC INTERROGATORY # 2

**Reference:**
[Ex. A/1/1, p. 3]

**Interrogatory:**
Please confirm that the Share Purchase Agreement filed in EB-2016-0276 and in this Application remains identical in all respects, and has not been amended, modified, supplemented, or changed in any other way.

**Response:**
Not confirmed. See Exhibit I, Tab 5, Schedule 2.

# SEC INTERROGATORY # 3

**Reference:**
[Ex. A/2/1, Table 1]

**Interrogatory:**
SEC is concerned to understand the differences between Table 1 in the current application (the "Current Savings Table"), and EB-2016-0276, Ex. A/2/1, Table 1 (the "Previous Savings Table"). With respect to the two tables:

a. Please confirm that Year 1 in the Previous Savings Table was 2017, and Year 1 in the Current Savings Table is 2019.

b. Please confirm that the Status Quo OM&A in the Previous Savings Table was $52.6 million over ten years, and in the Current Savings Table is $60.7 million over ten years. Please explain in detail the $8.1 million increase in Status Quo OM&A.

c. Please confirm that the Hydro OM&A in the Previous Savings Table was $20.7 million over ten years, and in the Current Savings Table is $20.6 million over ten years. Please explain in detail why the Hydro One OM&A dropped while the Status Quo OM&A increased.

d. Please confirm that the Status Quo Capital in the Previous Savings Table was $31.5 million over ten years, and in the Current Savings Table is $36.6 million over ten years. Please explain in detail the $5.1 million increase in Status Quo Capital.

e. Please confirm that the Hydro Capital in the Previous Savings Table was $26.7 million over ten years, and in the Current Savings Table is $27.7 million over ten years. Please explain in detail why the Hydro One Capital increases so much less than the Status Quo Capital.

f. Please confirm that, as a result of the above changes, the Applicant is now forecasting that the ten year OM&A cost savings have increased from $31.9 million to $40.1 million, and the ten year capital cost savings have increased from $4.8 million to $8.9 million.

g. Ex. A/3/1, p. 2. Please reconcile the substantial increases in forecast savings with the drop in "guaranteed" earnings sharing from \$3.4 million in EB-2016-0276 to \$3.2 million in the current Application.

**Response:**

a) Year 1 of this application represents a 12 month period post-closing of the transaction which is assumed to most closely align with calendar year 2020. Year 1 in EB-2016-0276 was 2017.

b) The cumulative dollar amounts are confirmed.

The EB-2016-0276 status quo forecast portrays a long term average level of anticipated total OM&A expenditures. A more detailed Status Quo in this Application, which is now three years later, reflects OPDC's current forecast absent a transaction.

c) The cumulative dollar amounts are confirmed.

The current Application's Hydro One Forecast OM&A was updated since the time of the EB-2016-0276 Application. The current OM&A forecast anticipates slightly lower level of Hydro One operations costs to serve the former OPDC territory, with the net result being a very slight cumulative OM&A decrease when coupled with the three year time lag between the forecast periods (i.e. 2017-2026 vs 2020-2029).

d) The cumulative dollar amounts are confirmed.

The current application includes a more detailed Status Quo forecast which reflects OPDC's current capital forecast absent a transaction. Furthermore, there is a 3 year time lag between the forecast periods (i.e. 2017-2026 vs. 2020-2029) and the current forecast introduces a new OPDC operations centre in Year 9 (2028) which was not reflected in the EB-2016-0276 Status Quo

e) The main reason for the Hydro One capital expenditures increasing less versus the status quo relates to the new OPDC operations centre. See Exhibit I, Tab 1, Schedule 3 part a).

f) The cumulative dollar amounts are confirmed.

g) The reduction in Hydro Ones guaranteed ESM earnings sharing from $3.4 million in EB-2016-0276 to $3.2 million in the current Application is a reflection of three primary factors:

1) The revenue forecast to be collected from customers has not changed due to the ‘zero’ percentage rate Price Cap IR adjustment that has occurred since OPDC first informed the Board that OPDC and Hydro One had entered into discussions to undertake a consolidation transaction. As such the revenue line of the ESM has remained materially the same.

2) OPDC’s current rate base is starting at a higher point than it was in the EB-2016-0276 application. Therefore, over the 10 year period the additions lead to a higher rate base value. This allows more earnings (including the 300 basis points over the Board’s approved ROE) before sharing should begin. If this consolidation transaction had been approved in the earlier application ratepayers would have shared in more savings.

3) The period of time over which the comparative ESMs are forecast to operate has changed. In EB-2016-0276 the ESM period was assumed to occur between 2022 and 2026, while the current application assumes the ESM will be in effect 2025 and 2029. As such the inflationary cost impacts, due to the additional time taken to acquire OPDC, have been reflected - which as SEC points out reduces the ESM by approximately $0.2M.

SEC’s assertion that Hydro One will benefit from “substantial increases” in forecast savings in this Application versus EB-2016-0276 is unfounded and refuted by Hydro One.

# SEC INTERROGATORY # 4

**Reference:**
[Ex. A/2/1, p. 2]

**Interrogatory:**
Please identify any material differences in capitalization policies between Hydro One and OPDC. For any such differences, please show the impact of those differences on Table 1, and on all other comparisons of OPDC and Hydro One costs in the Application.

**Response:**
The only difference between OPDC's capitalization policy and Hydro One's capitalization policy relates to the capitalization of certain overhead costs under Hydro One's policy. In the Hydro One forecast capital costs noted in Exhibit A, Tab 2, Schedule 1, Table 1, there are no overhead costs as based on Hydro One's assessment they were deemed to be non-incremental. OPDC's capitalization policy does not allow allocation of general overheads to fixed assets. As such there is no difference between the Hydro One forecast capital costs and the Status Quo Orillia capital costs in Exhibit A, Tab 2, Schedule 1, Table 1.

# SEC INTERROGATORY # 5

**Reference:**
[Ex. A/2/1, p. 3]

**Interrogatory:**
SEC would like to better understand the impact of the comparison of OM&A per customer provided by the Applicant. Please provide the total (OM&A and capital) cost to serve each Hydro One UR customer in 2019 as set forth in the Draft Rate Order for EB-2017-0049. Please confirm that the OPDC total (OM&A and capital) cost to serve each of its residential customers in 2019 is more than the said 2019 Hydro One UR cost to serve. Please provide any supporting calculations.

**Response:**
Total allocated cost to serve Hydro One's UR customers in 2019 is (EB-2017-0049, Draft Rate Order, Exhibit 4.0, filed on April 5, 2019):

- 2019 total costs allocated to the UR rate class = $89,407,793
- 2019 forecast number of UR customers = 229,781
- 2019 cost to serve UR customers = $389/customer

It is confirmed that OPDC's total cost of serve each of its residential customers in 2019 is higher than the said Hydro One UR cost to serve. Below is the derivation of cost/customer for OPDC's residential class:

- 2019 OPDC total revenue requirement = $9,880,000 (EB-2018-0270, Attachment 18, filed on April 26, 2019)
- Percentage of total costs allocated to Residential customers per OPDC's last filed Cost Allocation Model = $4,263,450/$7,656,200 = 55.7% (EB-2009-0273, CAM filed on April 1, 2010)
- 2019 total costs allocated to the residential class = $9,880,000*55.7% = $5,503,160
- 2019 forecast number of residential customers = 12,512 (Exhibit I, Tab 5, Schedule 18)
- 2019 cost to serve residential customers = $5,503,160/12,512 = $440/customer

Hydro One notes again, that Hydro One's plan is not to integrate OPDC customers into Hydro One's existing UR rate class.

# SEC INTERROGATORY # 6

**Reference:**
[Ex. A/2/1, p. 5]

**Interrogatory:**
With respect to the proposal to amend the OPDC service charges:

a. Please provide a side by side table showing all of OPDC's approved service charges, and all of Hydro One's proposed service charges. If the proposal to update OPDC's service charges does not simply match each of the Hydro One service charges exactly, please provide an explanation of any exceptions.

b. Please provide a detailed estimate of the charges to OPDC customers in each of the deferred rebasing years using a) the current OPDC specific service charges, and b) the proposed Hydro One specific service charges.

**Response:**
a. Please refer to Exhibit I, Tab 1, Schedule 13.

b. Please refer to Attachment 1 for the estimate of the charges to OPDC customers in each of the deferred rebasing years utilizing both OPDC's SSC rates and Hydro One's SSC rates. The immaterial difference increases over time because it has been assumed that customer growth will increase by 0.8% per annum and that the utilization rate of these miscellaneous services will remain the same throughout the deferred rebasing period. The units expected over the deferred rebasing period have been based on the average use over the last four years.

| MISCELLANEOUS SERVICE REVENUES | OPDC Approved Rate | HONI Approved Rate | 2015 units | 2016 units | 2017 units | 2018 units | Avg 4 yrs # units forecast year 1-3 |
|---|---|---|---|---|---|---|---|
| Arrears Certificate | $15.00 | - | 13 | 8 | 12 | 6 | 10 |
| Easement Letter | $15.00 | $25.00 | 13 | 8 | 13 | 6 | 10 |
| Account History | $15.00 | - | | | | | |
| NSF Charge | $15.00 | $7.00 | 195 | 187 | 123 | 146 | 163 |
| Legal Letter | $15.00 | - | 13 | 8 | 12 | 6 | 10 |
| Account Set up / Change of Occupancy (plus credit agency costs if applicable) | $30.00 | $38.00 | 1,750 | 1,893 | 1,937 | 1,896 | 1,869 |
| Special Meter Reads | $30.00 | $30.00 | 0 | 5 | 1 | | 2 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | $30.00 | $30.00 | 0 | | | | |
| Collection of Account Charge - no disconnection | $30.00 | - | 5,147 | 5,772 | 3,233 | 2,973 | |
| Reconnection at meter - during regular hours | $65.00 | $65.00 | 104 | 110 | 117 | 141 | 129 |
| Reconnection at meter - after regular hours | $185.00 | $185.00 | | | | | |
| Reconnection at pole - during regular hours | $185.00 | $185.00 | | | | | |
| Reconnection at pole - after regular hours | $415.00 | $415.00 | | | | | |
| Specific charge for access to the power poles - $/pole/year (with exception of wireless attachments) | $43.63 | $43.63 | | | | 2,293 | 2,293 |
| **TOTAL MISCELLANEOUS SERVICE REVENUE** | | | | | | | |

Note: excluding transformer rentals and microFIT fixed service charges

| | | | | | | | 2.4% |
|---|---|---|---|---|---|---|---|
| **MISCELLANEOUS SERVICE REVENUES** | OPDC 2020 | HONI 2020 | OPDC 2021 | HONI 2021 | OPDC 2022 | HONI 2022 | **# units forecast year 4-6** |
| Arrears Certificate | $146 | - | $146 | - | $146 | - | 10 |
| Easement Letter | $150 | $250 | $150 | $250 | $150 | $250 | 10 |
| Account History | | - | | - | | - | |
| NSF Charge | $2,441 | $1,139 | $2,441 | $1,139 | $2,441 | $1,139 | 167 |
| Legal Letter | $146 | - | $146 | - | $146 | - | 10 |
| Account Set up / Change of Occupancy (plus credit agency costs if applicable) | $56,069 | $71,021 | $56,069 | $71,021 | $56,069 | $71,021 | 1,914 |
| Special Meter Reads | $60 | $60 | $60 | $60 | $60 | $60 | 2 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | | $0 | | $0 | | $0 | |
| Collection of Account Charge - no disconnection | | - | | - | | - | |
| Reconnection at meter - during regular hours | $8,385 | $8,385 | $8,385 | $8,385 | $8,385 | $8,385 | 132 |
| Reconnection at meter - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Reconnection at pole - during regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Reconnection at pole - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Specific charge for access to the power poles - $/pole/year (with exception of wireless attachments) | $100,044 | $100,044 | $100,044 | $100,044 | $100,044 | $100,044 | 2,348 |
| **TOTAL MISCELLANEOUS SERVICE REVENUE** | **$167,441** | **$180,898** | **$167,441** | **$180,898** | **$167,441** | **$180,898** | |

Note: excluding transformer rentals and microFIT fixed service charges

| MISCELLANEOUS SERVICE REVENUES | OPDC 2023 | HONI 2023 | OPDC 2024 | HONI 2024 | OPDC 2025 | HONI 2025 | 2.4%<br># units forecast year 7-10 |
|---|---|---|---|---|---|---|---|
| Arrears Certificate | $150 | - | $150 | - | $150 | - | 10 |
| Easement Letter | $153 | $256 | $153 | $256 | $153 | $256 | 10 |
| Account History | | - | | - | | - | |
| NSF Charge | $2,500 | $1,167 | $2,500 | $1,167 | $2,500 | $1,167 | 171 |
| Legal Letter | $150 | - | $150 | - | $150 | - | 10 |
| Account Set up / Change of Occupancy (plus credit agency costs if applicable) | $57,415 | $72,725 | $57,415 | $72,725 | $57,415 | $72,725 | 1,960 |
| Special Meter Reads | $61 | $61 | $61 | $61 | $61 | $61 | 2 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | | $0 | | $0 | | $0 | |
| Collection of Account Charge - no disconnection | | - | | - | | - | |
| Reconnection at meter - during regular hours | $8,586 | $8,586 | $8,586 | $8,586 | $8,586 | $8,586 | 135 |
| Reconnection at meter - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Reconnection at pole - during regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Reconnection at pole - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | 0 |
| Specific charge for access to the power poles - $/pole/year (with exception of wireless attachments) | $102,445 | $102,445 | $102,445 | $102,445 | $102,445 | $102,445 | 2,404 |
| **TOTAL MISCELLANEOUS SERVICE REVENUE** | **$171,459** | **$185,240** | **$171,459** | **$185,240** | **$171,459** | **$185,240** | |

Note: excluding transformer rentals and microFIT fixed service charges

| MISCELLANEOUS SERVICE REVENUES | OPDC 2026 | HONI 2026 | OPDC 2027 | HONI 2027 | OPDC 2028 | HONI 2028 | OPDC 2029 | HONI 2029 |
|---|---|---|---|---|---|---|---|---|
| Arrears Certificate | $153 | - | $153 | - | $153 | - | $153 | - |
| Easement Letter | $157 | $262 | $157 | $262 | $157 | $262 | $157 | $262 |
| Account History | | - | | - | | - | | - |
| NSF Charge | $2,560 | $1,195 | $2,560 | $1,195 | $2,560 | $1,195 | $2,560 | $1,195 |
| Legal Letter | $153 | - | $153 | - | $153 | - | $153 | - |
| Account Set up / Change of Occupancy (plus credit agency costs if applicable) | $58,793 | $74,471 | $58,793 | $74,471 | $58,793 | $74,471 | $58,793 | $74,471 |
| Special Meter Reads | $63 | $63 | $63 | $63 | $63 | $63 | $63 | $63 |
| Meter dispute charge plus Measurement Canada fees (if meter found correct) | | $0 | | $0 | | $0 | | $0 |
| Collection of Account Charge - no disconnection | | - | | - | | - | | - |
| Reconnection at meter - during regular hours | $8,792 | $8,792 | $8,792 | $8,792 | $8,792 | $8,792 | $8,792 | $8,792 |
| Reconnection at meter - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Reconnection at pole - during regular hours | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Reconnection at pole - after regular hours | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| Specific charge for access to the power poles - $/pole/year (with exception of wireless attachments) | $104,903 | $104,903 | $104,903 | $104,903 | $104,903 | $104,903 | $104,903 | $104,903 |
| **TOTAL MISCELLANEOUS SERVICE REVENUE** | **$175,574** | **$189,686** | **$175,574** | **$189,686** | **$175,574** | **$189,686** | **$175,574** | **$189,686** |

Note: excluding transformer rentals and microFIT fixed service charges

# SEC INTERROGATORY # 7

**Reference:**
[Ex. A/2/1, p. 8]

**Interrogatory:**
Please confirm that, under the Board's current ten year deferred rebasing policy, Hydro One's legacy customers will subsidize the rates of OPDC customers during that period with respect to 100% of the Shared Costs to serve the OPDC customers, and after the end of the deferred rebasing period under the current Hydro One proposal Hydro One's legacy customers will continue to subsidize the rates of OPDC customers with respect to part of the Shared Costs to serve the OPDC customers

**Response:**
Not confirmed. Hydro One's legacy customers will not subsidize OPDC customers during or after the deferred rebasing period. During the deferred rebasing period, OPDC customers will continue to be charged OPDC's OEB-approved base distribution rates plus LV charges, with a 1% reduction in Years 1 to 5 followed by price cap adjustments in years 6 – 10. Hydro One's legacy customers are therefore not "subsidizing" OPDC customers over that period. Hydro One's legacy customers will continue to pay rates during the deferral period that they would have paid if the transaction did not occur – they are not paying any cost or "subsidy" additional to what they would be paying in the absence of this transaction.

After the rebasing period, OPDC customers will be allocated a portion of Hydro One's shared costs, up to the amount of the goal post as defined in Exhibit A, Tab 4, Schedule 1. Any allocation of costs to OPDC customers' rates would be to the benefit of Hydro One's legacy customers as those costs will no longer be included in their revenue requirement. Hydro One is forecasting $9.3M of savings that both customer groups will benefit from.

# SEC INTERROGATORY # 8

**Reference:**
[Ex. A/2/1, p. 12]

**Interrogatory:**
SEC is seeking to understand the "economies of scale" that Hydro One claims it can deliver as a result of the proposed transaction:

a. Please explain why the two largest distributors in the province (Hydro One and Toronto Hydro), and therefore the ones with the greatest economies of scale, are also two of the highest cost distributors. Please provide any studies, analyses, or other empirical evidence known to Hydro One that shows that Hydro One and/or Toronto Hydro have material economies of scale despite their high costs of service. If Hydro One is not able to provide any evidence supporting its claim, please provide reasons why the Board should assume that such economies of scale will arise.

b. Please confirm that Hydro One has acquired more than 80 smaller distributors in the province of Ontario. Please provide any studies, analyses, or other empirical evidence that shows that, on an overall basis, the cost to serve the customers of those acquired distributors today is less than the cost to serve them if they had remained independent as a result of economies of scale.

**Response:**
a. Relevant to the Application are the economies of scale achieved by the combined operation of Hydro One and OPDC and not the economies of scale within either of Hydro One or Toronto Hydro.

   A larger customer base resulting from the creation of a larger regional distributor leads to costs for processing systems, such as billing, customer care, human resources and financial, being spread over a larger group of customers. Consolidation of these functions results in efficiency benefits as duplicate systems and staff positions are eliminated, leading to lower capital and operating costs over time. In addition to that, there are administrative savings arising from the elimination of redundant senior management and administrative functions.

As well, Hydro One's cost of borrowing is typically lower than that of smaller LDCs, leading to savings in financing costs over time. These savings arise in two respects:

- Lower overall debt costs on the acquired LDC's existing rate base, relative to the status quo, assuming Hydro One refinances higher-cost debt assumed in the transaction.

- Ripple effects from expected capital savings over time, leading to a reduced rate base and hence lower debt and equity return costs relative to the status quo.

In addition, qualitative benefits able to be realized in an acquisition by Hydro One of a smaller LDC include the following:

- Continued employment for all staff of acquired LDCs - Although redundant staffing functions will be eliminated as part of the integration process, leading to efficiency gains, Hydro One, due to its size and current staff retirement profile, is able to offer continued employment to staff of acquired LDCs. This is a benefit that smaller would-be acquirers may not be able to offer.

- Enhanced call centre service to customers – Hydro One has a sophisticated call-centre operation which typically offers longer hours of service and web access than do smaller LDCs. In addition, Hydro One has launched a highly successful smart-phone application for real-time outage management that customers can download to their devices, allowing instant access to outage information and estimated restoration times.

- Savings in recruitment, training, and staff development costs associated with the acquisition of trained and experienced utility staff that will be available to fill positions within Hydro One that will be available through expected retirements and other attrition.

b. Circumstances related to acquisitions unrelated to the transaction that is the subject of this Application are irrelevant. Hydro One's past acquisitions and mergers, that occurred prior to the Board's articulation of the "no harm" test and its Report on Rate-making Associated with Distributor Consolidation have been considered unnecessary in the Board's assessment of the "no harm" test in recent MAAD applications[1].

[1] EB-2013-0196, EB-2013-0187 and EB-2013-0198 – Decision and Order And Procedural Order 8 – January 24, 2014 – Page 5

# SEC INTERROGATORY # 9

**Reference:**
[Ex. A/2/1, p. 13]

**Interrogatory:**
SEC would like to better understand the current staffing of OPDC. Table 5 in the current Application shows 34 total staff, compared to 38 in Table 4 of EB-2016-0276, Ex. A/2/1, p. 9. Further, the reductions in the interim period are one "Back Office" person, three "Trades and Technical", and zero management. Please reconcile these changes in OPDC personnel with the Affidavit of Grant Hipgrave dated August 16, 2017, filed in EB-2017-0320.

**Response:**
Please refer to Exhibit I, Tab 4, Schedule 1 part b) for current OPDC staffing as of May 31, 2019 with a reconciliation of the changes compared to Table 5 of EB-2018-0270.

The information provided is a complete record of the current staffing situation at OPDC; Hydro One does not see the value in reconciling staffing numbers to prior applications.

# SEC INTERROGATORY # 10

**Reference:**
[Ex. A/2/1, p. 16 and A/3/1, p. 6]

**Interrogatory:**
SEC is trying to understand the claim that OPDC long-term debt in rates is at 6.25%. Please prepare an Appendix 2-OB model showing the current debt of OPDC, and with that model calculate the weighted average cost of debt if OPDC were to rebase this year.

**Response:**

OPDC's single source of long-term debt financing is via an interest only promissory note. The principal of this note, is $9,762,000 and is payable to the City of Orillia on December 31, 2030. The interest rate of this promissory note is 6.25%. Further details regarding the promissory note can be found in Note 8 to OPDC's 2018 financial statements.

OPDC's most recent OEB approved rates were last rebased during its 2010[1] cost of service rate application and the actual long-term debt rate of 6.25% was incorporated in its revenue requirement calculation and remains the current basis under which OPDC rates are currently set.

This long-term debt rate remains embedded in OPDC's current distribution rates paid by its customers today, and will continue to underpin the revenues Hydro One expects to receive from OPDC customers throughout the 10 year rebasing deferral period. As such Hydro One has appropriately used this rate in its ESM model

Given OPDC has only one long-term debt financing instrument, details of which have been provided above, the Applicants do not believe that completing an 'Appendix 2-OB' form would be helpful to the Board in this proceeding.

[1] EB-2009-0273

# SEC INTERROGATORY # 11

**Reference:**
[Ex. A/3/1, p. 3]

**Interrogatory:**
Please confirm that, under the Hydro One proposal, Hydro One would at no time calculate its actual earnings from the OPDC service territory, and would at no time share actual earnings with those customers.

**Response:**
Confirmed. As per Exhibit A, Tab 3, Schedule 1, Hydro One's proposal is that it will not use actuals to calculate the former OPDC service territory's earnings for years six through ten of the rebasing deferral period. Rather it will guarantee a payment of $3.2M in advance. As discussed in evidence the calculation of actual earnings will not be possible once integrated. Hydro One will not be producing separate financial statements for the OPDC service territory segment (this is one source of the synergy savings resulting from the transaction). Please see Exhibit I, Tab 4, Schedule 2 for more information on the benefits on Hydro One's proposed ESM.

# SEC INTERROGATORY # 12

**Reference:**
[Ex. A/3/1, p. 1, 4, 7]

**Interrogatory:**
With respect to the proposed ESM:

a. Please advise how Hydro One will assure the customers and the Board that the result of the guaranteed earnings sharing will be 50/50 for earnings 300 basis points above the allowed ROE of the OPDC service territory.

b. If the reason is that the earnings are forecast only, please reconcile this with the proposal to artificially increase forecast OM&A by 20% in the ESM forecast.

c. Please confirm that the OM&A increase reduces the calculated earnings sharing by $903,000.

d. Please confirm that the proposed ESM calculation assumes that the OPDC territory revenues are fully taxable, and that actual tax, after taking into account the fair market value bump, will be approximately $2 million lower, on a grossed-up basis.

e. Please provide an explanation, with all related CCA continuity schedules, of the reduction in taxes payable on Line 7 by $864,000.

**Response:**
a) Hydro One has proposed to implement a "guaranteed ESM" to operate in years 6 to 10 of the deferred rebasing period. As mentioned in prefiled evidence the proposed ESM will be calculated on forecast OM&A and capital expenditures. This will ensure that OPDC customers will benefit from the efficiencies and savings of the transaction, which was an aim of the Board's 2015 Consolidation Policy (page 7). The guaranteed ESM amount moves all the risk in attaining cost savings synergies to Hydro One. This will not only benefit customers in the refund of the ESM but further encourages Hydro One to ensure that these efficiencies are achieved which will benefit customers in the long term. Hydro One also notes that the ESM has been

calculated using only incremental costs – in other words the OM&A costs do not include OPDC customer's share of corporate overheads. If Hydro One included these costs, the overearnings for OPDC customers in years 6 to 10 would be lower.

Hydro One strongly believes providing a guaranteed ESM to OPDC's customers aligns with the intent and nature of the Board's policy to share any overearnings in the extended deferral period with ratepayers. Hydro One also believes its proposal is the most economic efficient solution for all parties, which will result in sustained lower ongoing capital and OM&A costs.

b) The 20% risk premium reflects the fact that the ESM refund is a guaranteed amount, with Hydro One absorbing all risks that the OM&A and capital forecasts provided in Exhibit A, Tab 2, Schedule 1 are achieved. These risks have been outlined on page 3 of Exhibit A, Tab 3, Schedule 1, with additional discussion found at Exhibit I, Tab 1, Schedule 20.

c) Please see Exhibit 1, Tab 1, Schedule 20, part d) for a calculation of the ESM without the 20% OM&A risk premium.

d) Not Confirmed. There is **no** related tax value bump impact included in Hydro One's ESM calculations. The tax bump has had, and will continue to have, no impact on the ratepayers of either Hydro One or OPDC, and Hydro One has reflected this in the ESM model. Please refer to Exhibit I, Tab 1, Schedule 18, part f) that confirms Hydro One's treatment of the tax bump is consistent with the regulatory principle that benefits follow costs.

Exhibit 1, Tab 5, Schedule 5 part d) of EB-2016-0276 also provides background that remains applicable regarding the PILs consequences of the transaction, including the consequences of the deemed disposition and acquisition, any departure tax or transfer tax payable.

e) For this question Hydro One assumes that SEC is asking for an explanation of the total of years 6 to 10 of the ESM tax calculation included in the Blue Page update filed April 26, 2019, compared to the original ESM Table 2 values filed September 27, 2016. As shown below:

**Tax Line Comparisons**
**Applications EB-2016-0276 vs EB-2019-0270**
**Information included at Exhibit A, Tab 3, Schedule 1**

| $000s | **Year 6** | **Year 7** | **Year 8** | **Year 9** | **Year 10** | **TOTAL** |
|---|---|---|---|---|---|---|
| EB-2018-0270 (Blue Page) | 794 | 813 | 832 | 853 | 870 | 4,161 |
| EB-2016-0270 (originally filed) | 960 | 983 | 1,005 | 1,029 | 1,049 | 5,026 |
| Difference | | | | | | (864) |

The difference, as outlined in Exhibit I, Tab 3, Schedule 11 was a result of a correction to the original ESM model ‘tax’ line, that was incorrectly capturing both the ‘current’ and ‘future’ tax amounts rather than just the ‘current’ tax line, and an error in the CCA category rates. Please see Exhibit I, Tab 3, Schedule 11.

# SEC INTERROGATORY # 13

**Reference:**
[Ex. A/3/1, p. 4]

**Interrogatory:**
Please provide the full "Hydro One ESM Model" in Excel format, with all formulae and assumptions intact.

**Response:**
Please find at Attachment 1 to this Exhibit Hydro One's ESM Model that underpins the Exhibit A, Tab 3, Schedule 1, including the Blue Page updates submitted April 26, 2019.

# SEC INTERROGATORY # 14

**Reference:**
[Ex. A/3/1, p. 7]

**Interrogatory:**
Please expand Table 2 to show years 1 to 5 as well, with all lines populated. Please provide the result in Excel format.

**Response:**
The ESM calculations over a 10 year period are not contemplated in the OEB's MAAD Handbook. The Handbook requires an ESM to be provided in the extended deferral period (beyond the first five years).

Any overearnings in Years 1 to 5 are permitted to be retained by the Acquiring utility. In the OEB's 2007 Report, "Rate-making Associated with Distributor Consolidation" the Board wrote:

> "In general, consolidation costs may include out-of-pocket/transaction costs, acquisition premiums, and restructuring costs. Regardless of the nature, timing, or certainty of expected benefits of a consolidation, <u>the ability to retain any achieved savings for a sufficient amount of time to provide a reasonable opportunity to at least offset the costs of a transaction</u> will be an important factor in a distributor's consideration of the merits of consolidation." [page 4 – emphasis added]; and

> "Allowing a distributor the option of scheduling the rate rebasing for the consolidated entity at any time up to the five-year limit accommodates distributors that may require an increase in operating, maintenance or capital expenditures shortly after closing of the transaction, as well as <u>distributors that wish to have the benefit of a longer period in which to off-set transaction costs with efficiency savings</u>." [page 5 – emphasis added]

The requested information is beyond the scope of the OEB's consideration in this proceeding.
The overearnings that are forecast to result from this transaction, in years 6 to 10 are provided in Exhibit A, Tab 3, Schedule 1, Table 2 and total $4.7 million prior to the tax

effect calculation, of which 50% will be shared with ratepayers. This is consistent with Hydro One's understanding of the Board's policy.

Notwithstanding Hydro One's view that the requested information is beyond the scope of the OEB's consideration in this proceeding, for the purposes of being responsive and in the interests of providing a summary of information contained in the ESM model for the first five years (per Attachment 1 of Exhibit I, Tab 2, Schedule 13 - located in the excel tab named "ESM Model" in rows 75 to 83), Table 1 below contains the information and calculation of forecast Net Profit after Tax in Years 1 to 5. Further calculations of over-earnings are not relevant as the ESM would only operate during the term of the extended deferred rebasing period (i.e. year 6 to 10). This is consistent with Hydro One's understanding of the Board's policy.

Hydro One also notes that Table 1 below does not include any OM&A transaction, integration or acquisition premium costs incurred by Hydro One, through which the OEB's MAAD policies the overearnings are intended to offset. Please see Exhibit I, Tab 2, Schedule 19.

**Table 1 - Earning Sharing Mechanism – Details Years 1 to 5 ($000's)**

| | **Deferral Period Year** | **1** | **2** | **3** | **4** | **5** |
|---|---|---|---|---|---|---|
| | **Calendar Year** | **2020** | **2021** | **2022** | **2023** | **2024** |
| 1 | Rate Base | 40,982 | 42,479 | 43,829 | 45,102 | 46,473 |
| 2 | Equity Component of Rate Base | 16,393 | 16,992 | 17,532 | 18,041 | 18,589 |
| 3 | Revenue | 16,372 | 16,442 | 16,513 | 16,584 | 16,655 |
| 4 | OM&A | 4,881 | 2,411 | 2,461 | 1,988 | 2,030 |
| 5 | Depreciation | 1,065 | 1,149 | 1,218 | 1,290 | 1,364 |
| 6 | Interest | 1,456 | 1,509 | 1,557 | 1,603 | 1,651 |
| 7 | Tax | 3 | 647 | 636 | 763 | 753 |
| **8** | **Net Profit After Tax** | **$1,391** | **$3,134** | **$3,036** | **$3,324** | **$3,236** |
| 9 | Achieved ROE (%) (Line 8 ÷ Line 2) | 8.49% | 18.44% | 17.32% | 18.42% | 17.41% |

# SEC INTERROGATORY # 15

**Reference:**
[Ex. A/3/1]

**Interrogatory:**
Please confirm that Hydro One plans to change the depreciation rates for OPDC rate base after the acquisition. Please confirm that, to the extent that the depreciation rates are lower than those used by OPDC, the difference each year will be credited to account 1576 and refunded to OPDC customers on rebasing. If that is not the case, please provide a detailed explanation of the proposed ratemaking treatment of the change in depreciation rates. Please quantify the reduced depreciation amount that, on current forecasts, Hydro One proposes to have taken during the deferred rebasing period than would arise at the OPDC depreciation rates.

**Response:**
Confirmed, Hydro One plans to change the depreciation rates for OPDC after the acquisition. Accounting standards (including USGAAP) would require that depreciation rates reflect management's best estimate for asset depletion. Post-acquisition, the OPDC assets would be under Hydro One's asset management and maintenance policies, and therefore the expected useful lives and resultant depreciation rates would be updated to reflect this.

Hydro One does not confirm that, if its depreciation rates are lower than those used by ODPC, the differences would be credited to account 1576 or refunded to ODPC customers on rebasing. Account 1576 (Accounting Changes under CGGAP) was established to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under Canadian GAAP in 2012 or as mandated by the Board in 2013[1]. It was not established in the context of a MAAD application.

---

[1] https://www.oeb.ca/oeb/_Documents/Regulatory/Board_Ltr_Acct_Policy_Changes_1575_1576_20130625.pdf

Hydro One regards items such as depreciation as part of the synergy savings of the acquisition, which will ultimately benefit OPDC customers through lower rates after the deferral period, as discussed in Exhibit A, Tab 4, Schedule 1.

The forecast depreciation expense that will be recorded by Hydro One on OPDC's assets is $1.1M in Year 2020 (the first year post-acquisition), and over the 10-year deferred rebasing period totals $12.8M. These numbers can be found in Hydro One's OPDC ESM Model, filed at Exhibit I, Tab 2, Schedule 13, Attachment 1, in Row 50 of the Tab named "ESM Model". The depreciation included in OPDC's current rates[2] is $1.4M or $14.1M over the 10-year deferred rebasing period.

Hydro One believes that items such as changes in depreciation (either increases or decreases) are part of the deferral period synergies associated with the acquisition, which are at the shareholders risk. Therefore, Hydro One will not record an amount in account 1576 relating to depreciation.

[2] EB-2009-0723

# SEC INTERROGATORY # 16

**Reference:**
[Ex. A/4/1, p. 1]

**Interrogatory:**
The Board in EB-2016-0276 said "*it would have been reasonable to see a forecast of costs to service Orillia customers beyond the ten year period*". Please show where in the evidence that forecast (i.e. not just the residual cost to serve, but the full cost to serve) has been provided. Please explain why Hydro One is comparing residual cost to serve, i.e. excluding certain costs to serve, with the full cost to serve in the Status Quo scenario. Please specify what conclusions, if any, Hydro One believes the Board can draw from that comparison in terms of the actual costs to serve OPDC customers in the future.

**Response:**
The total forecast cost to serve Orillia customers is provided in Exhibit A, Tab 4, Schedule 1. The OPDC status quo revenue requirement and the residual cost to serve are discussed in section 2 of that Schedule. Further on, in section 3 of that Schedule, Hydro One's shared costs are discussed as well as Hydro One proposed methodology for allocating costs after the deferral period.

Hydro One does not forecast shared costs for ANY of its customers on a rate class basis. Shared costs are captured at the corporate level, and it is only during the cost allocation process that an *allocation* of costs is assigned to rate classes. Therefore, the only reasonable comparison of costs that should be considered is the incremental costs to serve OPDC customers versus their status quo costs.

Based on the evidence Hydro One has provided throughout this application, the OEB can conclude that neither OPDC, nor Hydro One legacy customers will be harmed by this transaction.

# SEC INTERROGATORY # 17

**Reference:**

[Ex. A/4/1, p. 2, Attachments 18 and 20]

**Interrogatory:**

Please provide the full calculations underlying Table 1, on a year by year basis from Year 1 to Year 11, with explanations for any figures that are not fully explained by Attachment 20. Please confirm that the status quo assumption is that revenue requirement will increase at a compound annual growth rate of 3.5% per year from 2017 to 2030. Please disaggregate the growth rate into a) increases in weighted average unit rates, and b) increases in billing determinants.

**Response:**

Please find below a table representing the Table 1 data requested for the periods Year 1 to Year 11. The average annual revenue requirement increase over that period is 2.9%, and takes into consideration OPDC's expected rate rebasing years within the 2020 to 2030 period of 2020, 2025 and 2030.

**OPDC Status Quo Scenario**
**Calculation of Revenue Requirement**

| | Yr 1<br>2020<br>Fore. | Yr 2<br>2021<br>Fore. | Yr 3<br>2022<br>Fore. | Yr 4<br>2023<br>Fore. | Yr 5<br>2024<br>Fore. | Yr 6<br>2025<br>Fore. | Yr 7<br>2026<br>Fore. | Yr 8<br>2027<br>Fore. | Yr 9<br>2028<br>Fore. | Yr 10<br>2029<br>Fore. | Yr 11<br>2030<br>Fore. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Average of Net Book Value of Assets | 34,323 | 36,443 | 37,564 | 37,326 | 37,662 | 38,448 | 39,219 | 39,972 | 44,473 | 48,821 | 49,244 |
| Working Capital | 3,101 | 3,182 | 3,705 | 3,789 | 3,875 | 3,963 | 4,053 | 4,145 | 4,239 | 4,335 | 4,434 |
| **Rate Base** | **37,424** | **39,625** | **41,269** | **41,115** | **41,537** | **42,411** | **43,272** | **44,117** | **48,712** | **53,156** | **53,678** |
| **Revenue Requirement** | | | | | | | | | | | |
| OM&A | 5,542 | 5,654 | 5,768 | 5,883 | 6,000 | 6,120 | 6,243 | 6,367 | 6,493 | 6,621 | 6,754 |
| Depreciation | 1,571 | 1,711 | 1,817 | 1,875 | 1,958 | 2,061 | 2,167 | 2,277 | 2,517 | 2,762 | 2,882 |
| Cost of Capital - Debt Interest | 906 | 959 | 999 | 996 | 1,006 | 1,027 | 1,047 | 1,068 | 1,179 | 1,287 | 1,300 |
| Cost of Capital - Equity Return | 1,347 | 1,427 | 1,486 | 1,480 | 1,495 | 1,527 | 1,558 | 1,588 | 1,754 | 1,914 | 1,932 |
| Tax | 102 | 130 | 203 | 263 | 309 | 344 | 380 | 415 | 474 | 535 | 575 |
| **Revenue Requirement** | **9,468** | **9,881** | **10,273** | **10,497** | **10,768** | **11,079** | **11,395** | **11,715** | **12,417** | **13,119** | **13,443** |
| **Average Revenue Requirement Growth** | -4.2% | 4.4% | 4.0% | 2.2% | 2.6% | 2.9% | 2.9% | 2.8% | 6.0% | 5.7% | 2.5% |
| **Average Revenue Requirement Growth (2020 to 2030)** | | | | | | | | | | | **2.9%** |

Additional details regarding the calculation of OPDC's annual working capital are provided at Exhibit I, Tab 5, Schedule 20, Table 2.

# SEC INTERROGATORY # 18

**Reference:**

[Ex. A/4/1, p. 2, Attachments 18 and 20]

**Interrogatory:**

Please confirm that, taking into account depreciation each year, OPDC currently expects to spend more than $38 million on capital (plus customer contributions) over the 13 year period 2017 to 2030, a compound annual growth rate of 3.6% per year. Please provide the Distribution System Plan or similar document of OPDC supporting that level of capital spending. If there is no DSP or multi-year plan, please provide "OPDC's 2019 Rate Base forecast" referred to in Attachment 20, with all supporting documents and all assumptions explained.

**Response:**

OPDC is unsure which figures SEC has used to calculate the capital expenditure compound annual growth rate over the period indicated and is therefore unable to confirm the above statement.

OPDC's total capital spend (before contributed capital) over the **14-year** period (from 2017 to 2030) is forecast to be $53 million which is greater than the $38 million suggested in SEC's above statement. In terms of responding to SEC's implied capital expenditure growth rate, OPDC's gross capital expenditures were $3.5 M in 2017 in 2030 are forecast to be at the same level. Please refer to Table 1 below for more detail regarding OPDC's Status Quo annual capital expenditures up until 2030.

**Table 1- OPDC's Status Quo Actual and Forecast Annual Capital Expenditures – 2017 to 2030**[1]

| ($ in thousands) | Actual | YEE | Forecast | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| Service centre | 6 | 10 | 10 | 10 | 10 | 10 | 10 | | | | | 8,000 | | |
| Substations | 644 | 211 | 2,700 | | 2,800 | | 100 | | | | | | | |
| Poles & wires | 2,766 | 2,502 | 1,616 | 2,177 | 1,295 | 1,391 | 1,646 | | | | | | | |
| Meters | 80 | 134 | 44 | 383 | 163 | 33 | 33 | | | | | | | |
| Heavy Vehicles | | | 459 | 690 | | | | | | | | | | |
| Light vehicles | 10 | | 40 | 80 | 80 | 75 | 40 | | | | | | | |
| Other capital assets | 43 | 91 | 331 | 91 | 91 | 91 | 91 | | | | | | | |
| To be determined | | | | | | | | 2,900 | 3,000 | 3,100 | 3,200 | 3,300 | 3,400 | 3,500 |
| **GROSS CAPITAL EXPENDITURE** | **3,549** | **2,948** | **5,200** | **3,431** | **4,439** | **1,600** | **1,920** | **2,900** | **3,000** | **3,100** | **3,200** | **11,300** | **3,400** | **3,500** |
| Contributed capital | 349 | 250 | 162 | 218 | 130 | 139 | 165 | 150 | 160 | 170 | 180 | 190 | 200 | 210 |
| **NET CAPITAL EXPENDITURES** | **3,200** | **2,698** | **5,038** | **3,213** | **4,309** | **1,461** | **1,755** | **2,750** | **2,840** | **2,930** | **3,020** | **11,110** | **3,200** | **3,290** |

[1] The 2018 capital expenditures provided in Table 1 to this response are consistent with the 2018 value underpinning A-4-1 and Attachments 18 and 20. The 2018 value was a forecast estimate used prior to the production and audit of OPDC's year-end 2018 financial statements.

# SEC INTERROGATORY # 19

**Reference:**
[Ex. A/4/1, p. 8]

**Interrogatory:**
Please explain why Hydro One assumes that the OEB cost allocation model will not "reflect the cost to serve the acquired OPDC customers", and will have to be "adjusted" to do so. Please explain what steps would be taken to ensure that the adjustments result in just and reasonable rates, not just for OPDC customers, but for all other Hydro One customers.

**Response:**

Hydro One's experience with the OEB's cost allocation model (CAM) shows that the CAM allocates more distribution assets (USofA accounts 1815-1860) to the new acquired utility rate classes than are actually being used to serve those classes. Since the allocation of distribution assets is a key driver in allocating the large majority of other costs in the CAM, Hydro One effectively directly allocates the fixed assets required to serve the new acquired classes by adjusting the asset costs allocated by the CAM. The adjustments took the form of a percentage reduction to the Gross Fixed Asset (GFA), Net Fixed Asset (NFA) and Deprecation amounts for the acquired classes. The adjusted GFA and NFA amounts are then used within the CAM to allocate costs to *all* legacy and acquired rate classes following the cost allocation principles underlying the OEB's cost allocation model.

At the time rates are proposed for OPDC customers in year 11 Hydro One will assess the revenue-to-cost ratios resulting from the cost allocation model and make any adjustments necessary to bring them in line with the Board's approved revenue-to-cost ratio ranges in effect at the time. The revenues to be collected from OPDC customers will be compared against the goalposts defined by the Residual Costs to Serve plus LV Cost and the OPDC Status Quo plus LV Cost to ensure that the total revenue collected from OPDC customers falls between those two amounts.

As detailed in Exhibit A, Tab 4, Schedule 1, as long as the total revenue collected from OPDC customers falls between those goalposts, both Hydro One OPDC and legacy customers benefit from the acquisition of OPDC.

# SEC INTERROGATORY # 20

**Reference:**
[Ex. A/4/1, p. 9]

**Interrogatory:**
With respect to the proposed retroactive changes to the Status Quo Forecast:

a. Please provide examples of "unknown or unforeseen costs at that time" that would qualify for adjustment. For example, would higher than expected union wage raises require an adjustment? Or, would interest rate movements that are inconsistent with the forecast require an adjustment? Please provide sufficient examples so that the Board and parties can better understand the nature of the adjustments to be proposed.

b. Please confirm that "unanticipated costs' and "unanticipated events" are intended to be comparable to Z factors, as the Board currently defines them. If that is not the case, please provide a fuller explanation of that proposal.

c. Please confirm that cost decreases, whether "unknown or unforeseen", or "unanticipated", would also require adjustment to the Status Quo Forecast. Please advise whether that would include better than expected savings as a result of the consolidation of OPDC into Hydro One.

**Response:**
a) In Year 11, Hydro One will need to confirm the Year 11 Status Quo forecast of where OPDC's revenue requirement would have been in absence of the transaction. OPDC has provided a forecast of its OM&A and capital in Year 11. Hydro One in determining the Status Quo revenue requirement would start with the key costs supplied by OPDC, in Attachment 18 to the prefiled evidence; OM&A, Depreciation and Rate Base. If there was a major event that resulted in a substantive increase in capital expenditure and/or OM&A, Hydro One would also add these to the revenue requirement calculations.

"Unknown or unforeseen" costs that could be added are those that would have been incurred by OPDC in absence of the transaction and would have impacted OPDC's status quo revenue requirement. Examples include: major storms resulting in significant damage to distribution assets; new environmental legislation requiring the retirement and replacement of certain assets; changes to OEBs policies and rules (e.g. change in capital structure); changes to tax policies and rates, etc.

Items such as a change in union wage rates would not be included nor would minor changes to interest or inflation rates used to determine the forecast provided.

If there was a change in the Status Quo forecast as a result of any of these factors, Hydro One would provide evidence to the Board at the time of harmonization to explain any variances.

Once the operating costs have been determined, the revenue requirement for the status quo in Year 11 would be calculated using the OEB's then-current economic parameters and tax rates.

b) The "unanticipated costs" and "unanticipated events" contemplated could be similar to those that OPDC would have applied for through an ICM if it existed as a stand-alone company. As mentioned in part a) above, any material changes to the Status Quo forecast provided in Exhibit A, Tab 4, Schedule 1 will be subject to review by the OEB at a future rates proceeding at the time of harmonization.

c) Cost decreases, as a result of legislative changes, OEB policies that decrease the Status Quo costs would also be applied to determine the Status Quo forecast in Year 11. As mentioned in part a) above, in Year 11 Hydro One would re-calculate the Status Quo forecast using the OEB's then-current economic parameters (e.g. cost of capital) and tax rates. Cost savings driven by Hydro One due to the consolidation of OPDC into Hydro One will not adjust the status quo forecast.

# SEC INTERROGATORY # 21

**Reference:**
[Ex. A/4/1, p. 11]

**Interrogatory:**
Please explain what will happen to OPDC customers in Year 11 if the cost allocation model, after all adjustments, still shows costs to serve Hydro One customers in the OPDC service territory that are higher than the Status Quo Forecast.

**Response:**

a) The appropriate cost allocation and rate design applicable to OPDC customers will be determined in a future rate proceeding consistent with the OEB's cost allocation and rate design principles in effect at the time. Hydro One's MAAD Application commits to charging OPDC customers no more than the higher goal post amount of $14.4M. Under this scenario $6.5M ($14.4 - $7.9) in synergy and efficiency cost savings would accrue to the benefit of Hydro One's legacy customers, and OPDC customers would not be harmed as they would still be paying no more than what they would have been paying had they not been acquired.

   If the initial results from the cost allocation and rate design process result in total costs in excess of $14.4M being borne by OPDC customers (which is not expected to be the case as shown in the response to Exhibit I, Tab 1, Schedule 9), this would mean that Hydro One's legacy customers would be getting more than $6.5M in costs savings. In that situation Hydro One would propose a reduction in the revenue-to-cost ratios for the OPDC classes such that the costs to be borne by OPDC customers would not exceed $14.4M. While a reduction to the revenue-to-cost ratios for the OPDC customer classes would shift some costs to be collected to other Hydro One classes, this would not result in harm to Hydro One legacy classes but rather simply reduce the benefit that is accruing to them to the maximum value of $6.5M.

# SEC INTERROGATORY # 22

**Reference:**
[Ex. A/4/1, p. 12]

**Interrogatory:**
Please advise where "an illustration of how Shared Costs could be collected from customers of the former OPDC" is found in the Application.

**Response:**
An illustrative discussion of how Shared Costs will be collected from OPDC customers is provided in Section 3 of Exhibit A, Tab 4, Schedule 1 and also throughout Exhibit A, Tab 5, Schedule 1.

# SEC INTERROGATORY # 23

**Reference:**
[Ex. A/5/1, p. 2 and Ex. A/4/1, Table 4]

**Interrogatory:**
SEC is concerned with understanding the underlying drivers of the claimed ratepayer savings. With respect to Table 1 in the Update and Table 4 in the pre-filed evidence, please provide a detailed breakdown, for each year, of the components of the "ratepayer savings" of $6.5 million.

**Response:**
Table 1 in Exhibit A, Tab 5, Schedule 1 shows the savings for OPDC customers in Year 11. The LV charges under the status quo will be recovered through a separate rate whereas in the residual cost to serve these LV charge related costs are included within the calculation of the Residual Cost to Serve revenue requirement.

As confirmed in Exhibit I, Tab 1, Schedule 6 part b), the $6.5M of annual ratepayers savings are expected to be ongoing, compared to the status quo scenario in the absence of this transaction.

The table below provides a breakdown of all revenue requirement components plus LV Charges that make up the savings levels discussed above. OM&A and LV Charges make up approximately 85% of the ratepayer savings. Please refer to Exhibit I, Tab 1, Schedule 3b) for an explanation of the OM&A driver savings.

| ($000s) | Hydro One | OPDC | Savings |
|---|---|---|---|
| OM&A | 1,921 | 6,754 | (4,833) |
| Depreciation | 1,433 | 2,882 | (1,449) |
| Cost of Capital – Debt | 1,373 | 1,300 | 73 |
| Cost of Capital – Equity | 1,905 | 1,932 | (27) |
| Tax | 227 | 575 | (348) |
| **Revenue Requirement (without LV Charges)** | **6,859** | **13,443** | **(6,584)** |
| LV Charges | - | 1,005 | (1,005) |
| **Cost to serve** | **6,859** | **14,448** | **(7,589)** |

# SEC INTERROGATORY # 24

**Reference:**
[A/5/1, p. 3]

**Interrogatory:**
Please explain how, once the rates are harmonized, customers can be confident that they will continue to benefit from savings from the acquisition into the future, if the costs to serve the acquired customers are no longer being tracked

**Response:**
The savings that Hydro One has forecast in OM&A are ongoing savings which will benefit OPDC customers into the future. Hydro One has committed to track capital costs to serve the OPDC service territory beyond the deferral period which will be used to substantiate the rates for OPDC customers. Please see Exhibit I, Tab 4, Schedule 32.

The rebasing in Year 11 locks in the acquisition savings in the Year 11 rates established for the OPDC customers. Any rate adjustments beyond the first rebasing period (i.e. 16 years into the future and beyond) will be in accordance with the OEB's cost allocation and rate design policies in effect at the time.

Given that OPDC's Year 11 rates will result in rates below the status quo, Hydro One has no reason to believe that future rates will be in excess of what the customers of OPDC would have faced in absence of the transaction. Hydro One will track all capital expenditures associated with serving OPDC's customers; these expenditures will be reviewed by a future OEB panel for need and prudency. Hydro One expects that any future investments required in the OPDC service territory to ensure the safe and reliable supply of electricity, and satisfy all applicable standards at the time, would have been required whether or not OPDC was purchased by Hydro One. There is also no basis for reliably establishing what the OPDC status quo costs would have been 16 years into the future and beyond.

All cost allocation and rate design proposals in subsequent years will be reviewed and tested by the OEB as part of a future rates application.

# SEC INTERROGATORY # 25

**Reference:**
[A/5/1, p. 3]

**Interrogatory:**
The Applicants state that they are unable to "track…the costs associated with certain Hydro One resources that OPDC customers will enjoy the benefit of". Please confirm that the Applicants can track the amounts with respect to those costs that would be allocated to the OPDC customers if they were allocated on the same basis as the legacy customers.

**Response:**
This question is confusing tracking costs and cost allocation to determine rates.

The quoted statement was referencing the capital costs that Hydro One would be tracking to serve the customers of OPDC. These are costs that Hydro One would not incur if the transaction did not proceed. During Hydro One's recent Distribution Rates proceeding (EB-2017-0049), concerns were raised that Hydro One would not track capital costs for the Acquired Utilities beyond the time "Hydro One applies for new rates"[1] as directed in the MAADs decision. In Exhibit A, Tab 5, Schedule 1, page 2, Hydro One commits to continue to track capital costs to serve OPDC customers after the rebasing period, which ensures that rates for OPDC customers and any fixed asset adjustment factors that will be used, will be informed by the most up-to-date asset cost data.

Hydro One is unable to track actual "shared costs" for any of its customer groups. These costs are incurred at the corporate level and are not directly charged to any of Hydro One's rates classes. For instance, Hydro One's Finance department's costs (which would be captured in "shared costs") are neither forecast nor tracked between Hydro One's Rural, UR, GSd or Acquired rate classes. Shared costs for all Hydro One customers have always only been recorded at a corporate level.

---

[1] EB-2014-0213 – Decision and Order, page 21; EB-2014-0244 – Decision and Order, page 3; EB-2013-0196/0187/0198 – Decision and Order, page 25.

# SEC INTERROGATORY # 26

**Reference:**
[A/5/1, p. 4, 7]

**Interrogatory:**
In the EB-2017-0049 Decision with Reasons, at p. 161/2, the Board said:

> *"As SEC argued, Hydro One's rate proposal is based on a snapshot of the existing asset base in the acquired service area. The OEB agrees and based on Hydro One's failure to demonstrate that its costs are the same or lower in its evidence,[308] finds that the proposal will result in one of the two following negative outcomes.*
>
> *a) In the absence of recalibration of the adjustment factors, an undue subsidy from Hydro One's legacy customers would be required.*
>
> *b) In the situation where the calibration of the adjustment factors is commensurate with asset renewal at Hydro One's higher costs, harm in the form of relatively higher rates to the customers of the Acquired Utilities would need to be imposed."*

Please explain how the current proposal for OPDC will not produce either

a. A situation in which legacy customers bear part of the costs fairly attributable to OPDC customers, or

b. As OPDC assets are replaced with higher cost Hydro One assets over time, and the adjustment factor is reduced, the OPDC customers will be harmed by higher longer term rates.

**Response:**

a) With respect to item a), Hydro One's legacy customers will not be charged costs that are directly attributable to serving the customers of OPDC. The opposite is true – legacy customers will benefit from the allocation of Hydro One's Shared Costs to the acquired OPDC rate classes. In the absence of this transaction, legacy customers would not benefit from having those costs shared – instead, they would be 100% recovered from legacy customers. With respect to item b), Hydro One is proposing to track the capital cost to serve OPDC customers beyond rate harmonization at the end of the deferred rebasing period, which will inform the fixed asset adjustment factors that will be used to determine the costs that will be allocated to their rate classes to set rates.

b) Hydro One disagrees with the statement that OPDC assets will be replaced with "higher cost Hydro One assets over time" and there is no evidence on the record to support this assertion. Any asset that is replaced after its useful life has expired; often 30 or more years hence, will be replaced at a higher cost than it was constructed at – regardless of which distributor replaces the asset.

It is not possible to know what the asset replacement costs for Hydro One and OPDC will be beyond the deferred rebasing period (i.e. after 2030). In its recent Distribution Application, Hydro One demonstrated its commitment to finding efficiencies and productivity savings that will further reduce Hydro One's asset replacement cost and asset replacement rate (e.g., exploring a pole refurbishment program).

# SEC INTERROGATORY # 27

**Reference:**
[A/5/1, p. 4-6]

**Interrogatory:**
In the EB-2017-0049 Decision with Reasons, at p. 162, the Board said:

> *"The OEB has provided clear guidance with respect to its expectations that evidence of lower cost structures relied on in acquisition proposals are expected to result in concomitant lower rates. Hydro One would be expected to apply any distinguishable cost causation analysis relied on in an acquisition application to any customers that met the identified cost causation criteria whether they are new or legacy customers. The OEB did not direct Hydro One to isolate the Acquired Utilities in its cost allocation methodology. Hydro One has not demonstrated that its proposal is equitable to all customers." [emphasis added]*

Please confirm that, under the Applicants' new proposal, Customers in towns like Brockville, Smith's Falls, Ancaster and other Hydro One service areas of a similar size and density to Orillia will also have their costs allocated using adjustment factors similar to those being applied to OPDC. If that is not confirmed, please explain how the Applicants' current proposal complies with the direction of the Board as set forth above.

**Response:**
Hydro One is not proposing to create new rate classes for customers in the specific communities referenced. Other than using adjustment factors to specifically allocate the fixed assets associated with serving customers in the OPDC service territory, Hydro One will use the same cost causation principles implicit in the Board's cost allocation model to allocate costs to all rate classes, including legacy and any new acquired classes. The distinguishing characteristic of the new acquired classes is that they relate to a specific geographic area for which specific assets required to serve are known, given that OPDC existed as a separate utility prior to being acquired. This will allow rates to be set for the OPDC acquired classes that best reflect their specific cost-to-serve. Hydro One does not track the cost to serve its legacy customers on a geographic basis, therefore the same

information is not available for the individual communities referenced, and in any case, it would not be feasible for Hydro One to establish separate rate classes for each of the large numbers of communities it serves.

# SEC INTERROGATORY # 28

**Reference:**

[A/5/1, p. 6]

**Interrogatory:**

Please confirm that all of the examples of adjustment factors cited apply to all customers with similar characteristics, and are all designed to ensure that like customers are allocated costs in a consistent manner. Please explain how the proposed adjustment factors for OPDC achieve a similar result.

**Response:**

Adjustment factors are intended to improve the accuracy of the allocation of costs to an established class of "like" customers. In the case of the OPDC acquired rate classes, the adjustment factors effectively directly allocate the fixed assets required to serve the OPDC classes. The OPDC classes have similar characteristics in that they contain customers associated with the geographic area of the OPDC service territory.

# SEC INTERROGATORY # 29

**Reference:**
[A/5/1, p. 7]

**Interrogatory:**
SEC is seeking to better understand how the adjustment factors will change over time as Hydro One replaces OPDC assets. For each of the categories of assets to which the adjustment factors are proposed to apply, please provide

a. The most recent actual unit costs to Hydro One of new assets in each of those categories, and the most recent actual unit costs to OPDC of new assets in each of those categories, and an explanation as to any material differences in unit costs.

b. The current OPDC book value per customer, by rate class, for each of those asset categories, and the current Hydro One book value per customer, by rate class, for each of those asset categories, plus any further information (such as weighted average vintage data) that can help the Board and parties understand any material differences in book value per customer for those asset categories.

**Response:**
a) The requested unit cost data is not available by USofA to which the adjustment factors apply.

b) The current OPDC book value per customer by rate class is not available. The Hydro One 2018 forecast book value per customer[1], by rate class, for each of the USofA asset categories to which the adjustment factors are proposed to apply are provided in the table below:

[1] As per EB-2017-0049, Draft Rate Order Exhibit 3.1, filed April 5, 2019

**HONI 2018 Forecast Gross Book Value of USofAs 1815-1860 by Rate Class (per EB-2017-0049)**
**($/per Customer)**

| Rate Class | 1815 | 1820 | 1825 | 1830 | 1835 | 1840 | 1845 | 1850 | 1855 | 1860 |
|---|---|---|---|---|---|---|---|---|---|---|
| UR | 30 | 115 | - | 671 | 394 | 5 | 486 | 358 | - | 377 |
| R1 | 67 | 240 | - | 1,447 | 846 | 10 | 943 | 538 | - | 377 |
| R2 | 215 | 848 | - | 4,591 | 2,650 | 30 | 2,492 | 1,075 | - | 377 |
| Seasonal | 43 | 20 | - | 1,489 | 887 | 11 | 1,649 | 717 | - | 377 |
| GSe | 228 | 1,290 | - | 4,963 | 2,783 | 31 | 4,302 | - | - | 676 |
| GSd | 3,871 | 29,189 | - | 60,780 | 40,421 | 494 | 110,632 | - | - | 6,752 |
| UGe | 124 | 913 | - | 2,839 | 1,562 | 18 | 3,018 | - | - | 676 |
| UGd | 2,293 | 18,359 | - | 35,067 | 23,366 | 283 | 61,619 | - | - | 6,752 |
| St Lgt | 94 | 1,038 | - | 5,763 | 3,152 | 42 | 4,260 | - | - | - |
| Sen Lgt | 3 | 3 | - | 508 | 290 | 4 | 630 | - | - | - |
| USL | 35 | 27 | - | 1,154 | 689 | 9 | 1,268 | - | - | - |
| DGen | 180 | 121 | - | 1,467 | 1,103 | 10 | 1,139 | - | - | 8,016 |
| ST | 62,511 | 55,492 | - | 171,292 | 135,807 | 1,990 | 39,560 | - | - | 25,670 |

# SEC INTERROGATORY # 30

**Reference:**
[A/5/1, p. 7]

**Interrogatory:**
Please provide a run of the cost allocation model for 2018, using Board-approved costs, book value, and all other necessary assumption, to show how costs would be allocated to OPDC on a harmonized basis under the Hydro One proposal if that allocation took place in 2018. For the purposes of this sample allocation, please assume that all of the cost savings expected over the next ten years as a result of the OPDC acquisition have been realized.

**Response:**
A 2018 cost allocation model run, using Hydro One 2018 data and OPDC data that reflects the savings expected over the next ten years would not appropriately reflect Hydro One's proposals in this application. The best way to capture all of the cost savings expected over the next ten years, and appropriately allocate costs to all legacy and OPDC customers, is to run a cost allocation model that reflects both what Hydro One and the OPDC costs would be at the end of the deferred rebasing period. The response to Exhibit I, Tab 1, Schedule 9 provides a cost allocation run showing an estimate of "the costs that would be allocated to the new OPDC acquired rate classes on a harmonized basis under Hydro One's proposal" as requested in this interrogatory.

# SEC INTERROGATORY # 31

**Reference:**
[A/5/1, p. 7]

**Interrogatory:**
In the EB-2017-0049 Decision with Reasons, at p. 162, the Board said:

> *"Hydro One's cost allocation evidence indicates that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired Utilities are higher than the costs of those previous utilities. This is in direct contradiction to the evidence relied on in its acquisition proposals."*

Please confirm that this statement is true with respect to OPDC as well, i.e. that absent any adjustment factors the costs normally allocated to OPDC customers would be higher than status quo costs.

**Response:**
The proposed adjustment factors ensure that only the actual local fixed assets used to serve the OPDC service territory are allocated to the OPDC acquired classes. Without the adjustment factors, the OPDC acquired classes would be allocated the average costs associated with serving Hydro One's entire service territory, which would not be an accurate reflection of the cost to serve the specific geographic area associated with the OPDC service territory. This inaccurate allocation of costs would be higher than the OPDC status quo.

# SEC INTERROGATORY # 32

**Reference:**
[A/5/1, p. 7]

**Interrogatory:**
Please provide a detailed list of the current Shared Costs of Hydro One, and provide the amount of each such Shared Cost currently allocated to each UR, UGe, UGd, R1, GSe, and GSd customers as of the most recent cost allocation by Hydro One.

**Response:**
Not all Shared costs are specifically identified as such within the cost allocation model, and in many cases are bundled together with costs that would be directly associated with providing local service. However, the bulk of the costs included in the "Customer and Related Costs (cu)" and "General and Administration (ad)" categories in Sheet O1 of the cost allocation model would be Shared costs. A summary of the 2018 OM&A costs included in the "cu" and "ad" categories is provided in the table below.

| USoA Account # | Accounts | O1 Grouping | "Shared" OM&A Costs per Hydro One's 2018 CAM (EB-2017-0049 Draft Rate Order, Exhibit 3.1, filed on April 5, 2019) | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Total | UR | UGe | UGd | R1 | GSe | GSd |
| 5065 | Meter Expense | cu | $14,137,661 | $2,170,502 | $308,323 | $78,008 | $4,278,036 | $1,505,649 | $235,550 |
| 5070 | Customer Premises - Operation Labour | cu | $26,252,103 | $4,571,095 | $362,430 | $34,935 | $9,009,581 | $1,769,873 | $105,490 |
| 5075 | Customer Premises - Materials and Expenses | cu | $3,360,287 | $585,103 | $46,391 | $4,472 | $1,153,233 | $226,545 | $13,503 |
| 5310 | Meter Reading Expense | cu | $5,046,045 | $27,674 | $68,552 | $156,981 | $194,712 | $655,153 | $603,704 |
| 5315 | Customer Billing | cu | $24,603,908 | $4,094,841 | $649,338 | $219,069 | $8,070,889 | $3,170,947 | $661,494 |
| 5320 | Collecting | cu | $5,016,934 | $834,971 | $132,405 | $44,670 | $1,645,719 | $646,581 | $134,884 |
| 5335 | Bad Debt Expense | cu | $21,835,117 | $3,102,925 | $520,763 | $297,643 | $7,612,575 | $2,248,388 | $1,543,290 |
| 5340 | Miscellaneous Customer Accounts Expenses | cu | $4,255,666 | $708,273 | $112,314 | $37,892 | $1,395,998 | $548,469 | $114,417 |
| 5410 | Community Relations - Sundry | ad | $609,399 | $45,356 | $9,094 | $9,377 | $134,104 | $65,741 | $46,146 |
| 5420 | Community Safety Program | ad | $303,426 | $14,885 | $4,609 | $7,224 | $54,947 | $35,428 | $37,283 |
| 5605 | Executive Salaries and Expenses | ad | $9,804,593 | $729,733 | $146,316 | $150,872 | $2,157,589 | $1,057,709 | $742,437 |
| 5610 | Management Salaries and Expenses | ad | $32,849,459 | $2,444,909 | $490,220 | $505,483 | $7,228,820 | $3,543,764 | $2,487,473 |
| 5615 | General Administrative Salaries and Expenses | ad | $46,437,125 | $3,456,207 | $692,993 | $714,568 | $10,218,909 | $5,009,586 | $3,516,378 |
| 5625 | Administrative Expense Transferred Credit | ad | ($76,323,252) | ($5,680,562) | ($1,138,991) | ($1,174,452) | ($16,795,621) | ($8,233,669) | ($5,779,458) |
| 5630 | Outside Services Employed | ad | $16,607,065 | $1,236,025 | $247,831 | $255,547 | $3,654,535 | $1,791,552 | $1,257,544 |
| 5635 | Property Insurance | ad | $4,172,723 | $204,701 | $63,383 | $99,351 | $755,627 | $487,205 | $512,718 |
| 5655 | Regulatory Expenses | ad | $11,894,496 | $885,280 | $177,504 | $183,031 | $2,617,491 | $1,283,165 | $900,692 |
| 5665 | Miscellaneous General Expenses | ad | $16,863,651 | $1,255,122 | $251,660 | $259,496 | $3,710,999 | $1,819,232 | $1,276,973 |
| 5670 | Rent | ad | $9,173,049 | $682,729 | $136,892 | $141,154 | $2,018,612 | $989,579 | $694,615 |
| 5675 | Maintenance of General Plant | ad | $73,362,373 | $5,460,190 | $1,094,805 | $1,128,891 | $16,144,053 | $7,914,253 | $5,555,250 |
| 6105 | Taxes Other Than Income Taxes | ad | $4,523,302 | $221,710 | $70,829 | $108,162 | $813,067 | $541,079 | $559,165 |
| 6205 | Donations | ad | $4,038,000 | $300,539 | $60,260 | $62,136 | $888,598 | $435,615 | $305,771 |
| | **Total** | | **$258,823,131** | **$27,352,208** | **$4,507,924** | **$3,324,509** | **$66,962,473** | **$27,511,845** | **$15,525,319** |

# SEC INTERROGATORY # 33

**Reference:**
[A/5/1, p. 8, 10, 11]

**Interrogatory:**
Please describe in detail the principles Hydro One proposes to apply in determining the revenue to cost ratios of the rate classes to which former OPDC customers would be allocated, including any changes to those principles over time (for example, five years after harmonization, ten years after harmonization, etc.).

**Response:**
Hydro One proposes to follow the same process both at the time of rate harmonization and in all subsequent rebasing applications (e.g. five years after harmonizations, ten years after, etc.). At the cost allocation stage, Hydro One will follow the Board's normal process implicit within the CAM to determine the R/C ratio for all rate classes, including OPDC rate classes, by comparing the "Total Revenue at Status Quo Rates" against the revenue requirement (i.e. costs) allocated to each rate class. At the rate design stage Hydro One will adjust the R/C ratios for each class if necessary, and to the minimum extent as may be needed, to bring them within the Board's approved R/C ratio range.

This is the approach that has been followed in the response to interrogatories at Exhibit I, Tab 1, Schedules 9 and 10, the results for which are summarized below.

| Class | R/C Ratio Resulting from CAM | R/C ratio Resulting from Rate Design Process |
|---|---|---|
| Acquired Residential | 0.94 | 0.94 |
| Acquired GS <50 | 0.88 | 0.88 |
| Acquired GS >50 | 0.97 | 0.97 |

# SEC INTERROGATORY # 34

**Reference:**
[A/5/1, p. 9]

**Interrogatory:**
SEC is seeking to understand the purpose and import of the Navigant evaluation. Please explain the expertise that Navigant purported to apply in its evaluation that is not already the expertise of the Board itself.

**Response:**
Navigant has considerable experience developing and implementing cost allocation methods and models in general, and more specifically for utilities that operate in service territories that span multiple regulatory jurisdictions (see Exhibit I, Tab 3, Schedule 17). The principles used in those instances are relevant to Hydro One's proposal to establish separate classes for the customers of the acquired utility. Navigant was asked to focus on Hydro One's proposed method of cost allocation and rate design after the 10-year rate stabilization period, given that there appeared to be some concerns about Hydro One's proposal with respect to its previous Acquired Utilities (as highlighted in the OEB's decision and order regarding Hydro One's 2018 to 2022 distribution rate application, OEB proceeding EB-2017-0049). The scope of Navigant's review is noted in response to Exhibit I, Tab 3, Schedule 15. Hydro One believes an independent third-party analysis of its cost allocation and rate design proposal would be of assistance to the Board and to the participants in the proceeding.

# SEC INTERROGATORY # 35

**Reference:**
[A/5/1, p. 10]

**Interrogatory:**
Please explain how costs will be allocated at any time if the "Post-Consolidation Cost to Serve" OPDC customers is greater than the status quo revenue requirement for those customers. Please calculate at what percentage allocation of Shared Costs to OPDC customers will result in total cost to serve being greater than status quo.

**Response:**
No special treatment is required if the "Post-Consolidation Cost to Serve" OPDC customers is greater than the status quo revenue requirement provided that the costs proposed to be collected in rates from the acquired classes, based on the revenue to cost ratios established by the cost allocation and rate design process, do not exceed the status quo revenue requirement.

However, as shown in Exhibit I, Tab 1, Schedule 9, this is not expected to be an issue for OPDC given that both the "Post-Consolidation Cost to Serve" and the costs to be collected from the acquired classes based on the revenue to cost ratios established by the rate design process are below the status quo revenue requirement.

Given the year 11 status quo cost (including LV charges) is $14.4M and the residual cost is $6.9M, an allocation of more than $7.5M of Shared Costs being borne by the OPDC acquired classes will result in costs that exceeds the status quo. $7.5M of shared costs represents 109% of residual costs, or 52% of status quo.

# SEC INTERROGATORY # 36

**Reference:**
[A/5/1, App. A]

**Interrogatory:**
SEC is seeking to better understand the report of Navigant. In its EB-2017-0049 Decision with Reasons, at p. 161-2, the Board said:

> *"The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.*
>
> *1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement. The OEB accepts VECC's submission that given the wide range of past rate adjustments, the rebasing rate increase for any utility can vary widely from the 6.3% average.*
>
> *2) Hydro One's proposal is based on a cost allocation approach that recognizes the existing assets of the Acquired Utilities as being distinguishable and at a lower cost than its legacy assets by using adjustment factors. It intends to revisit this approach and proposes to recalibrate the adjustment factors over time as assets are renewed in the acquired service areas. The new assets will be included in Hydro One's existing asset pool at a higher cost and result in a lowering of the adjustment factors over time.*
>
> *OEB staff submitted that Hydro One's proposal is reasonable because the adjustment factors are, in effect, performing a direct allocation of assets and depreciation to the Acquired Utilities. OEB staff accepted that where costs associated with specific rate classes are known, direct allocation is appropriate. OEB staff submitted that Hydro One's proposal to use the adjustment factors for capital and the allocation of*

*OM&A costs based on the cost allocation model is a reasonable proxy for reflecting the cost to serve.*

*The OEB accepts that Hydro One's proposal adheres to some basic cost allocation principles that may be acceptable in a general sense. However, it is not acceptable to ignore the basis on which the approvals for acquiring the utilities were granted.*

*As SEC argued, Hydro One's rate proposal is based on a snapshot of the existing asset base in the acquired service area. The OEB agrees and based on Hydro One's failure to demonstrate that its costs are the same or lower in its evidence,[308] finds that the proposal will result in one of the two following negative outcomes.*

*a) In the absence of recalibration of the adjustment factors, an undue subsidy from Hydro One's legacy customers would be required.*

*b) In the situation where the calibration of the adjustment factors is commensurate with asset renewal at Hydro One's higher costs, harm in the form of relatively higher rates to the customers of the Acquired Utilities would need to be imposed.*

*3) Hydro One argued that its proposal adheres to previous OEB determinations with respect to treating the Acquired Utilities as separate rate classes and that its proposal to do so is in response to OEB direction. The OEB does not accept Hydro One's contention. The OEB has provided clear guidance with respect to its expectations that evidence of lower cost structures relied on in acquisition proposals are expected to result in concomitant lower rates. Hydro One would be expected to apply any distinguishable cost causation analysis relied on in an acquisition application to any customers that met the identified cost causation criteria whether they are new or legacy customers. The OEB did not direct Hydro One to isolate the Acquired Utilities in its cost allocation methodology. Hydro One has not demonstrated that its proposal is equitable to all customers.*

> *4) Hydro One's cost allocation evidence indicates that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired Utilities are higher than the costs of those previous utilities. This is in direct contradiction to the evidence relied on in its acquisition proposals."*

With respect to each of the reasons of the Board set forth above, please provide Navigant's expert opinion explaining how the current Hydro One proposal complies with the Board's conclusions and expectations.

**<u>Response:</u>**

As stated in my evidence, Navigant was engaged to evaluate whether the cost allocation and rate design approaches described in Hydro One's supplemental evidence in this proceeding are appropriate and consistent with accepted regulatory practices, including, with respect to rate design, whether the adjustment of the revenue-to-cost ratio as described in the evidence is appropriate and consistent with accepted regulatory practices.

With respect to each of the Board's reasons for denying Hydro One's rates proposal as cited in its EB-2017-0049 Decision with Reasons, Navigant responds as follows:

1) Navigant was not asked to review Hydro One's assumption about the rate escalation for the status quo scenario.

2) a) Hydro One's supplemental evidence acknowledges (Exhibit A, Tab 5, Schedule 1, Page 7) the need to update the adjustment factors with each subsequent cost of service application.

   b) Updating the adjustment factors to reflect the continued tracking of gross fixed asset costs to serve the acquired customers does not necessarily mean that the total cost to serve or the rates paid by the acquired utility customers will be higher than what they would have been under the status quo.

   Utilities in general (Hydro One is not unique) have higher asset replacement costs than historical costs. Hydro One's replacement cost may be higher than the acquired utility's replacement costs, but they also may be the same or lower. As stated in Navigant's evidence (Page 8), Hydro One's proposal, to continue to recognise the OEB-approved revenue-to-cost ratio ranges, provides flexibility when setting rates that protects the acquired customers from rates that could exceed the status quo cost of service.

3) Hydro One's proposal to create separate customer classes for the acquired utilities' customers is a mechanism through which the lower cost structure resulting from the acquisition is reflected in the rates for the acquired utility customers' and the legacy Hydro One customers.

   Isolating the acquired utility customers by creating separate rate classes allows Hydro One to identify and directly assign the gross fixed asset costs to serve them, which in turn is used to allocate the majority of the other distribution related costs, such as operating, maintenance, and administrative costs, interest expenses, depreciation costs, and net income. Directly assigning the gross fixed asset costs to the acquired utility customer classes, and allowing the remainder of the costs to flow through the CAM using the standard allocation factors implicitly results in the same cost causation principles being applied to all customers.

   As stated in Navigant's evidence (Page 8), Hydro One's proposal, to continue to recognise the OEB-approved revenue-to-cost ratio ranges, provides flexibility when setting rates through which the benefits of the acquisition can be shared between the acquired and legacy customers.

4) Direct assignment is generally preferred to cost allocation as a way of attributing costs to customer classes. Hydro One's approach acknowledges this and incorporates adjustment factors into the CAM to recognize that the direct assigned costs of gross assets to serve the acquired customers are lower than the allocated gross assets derived using the standard allocation factors in the CAM.

# SEC INTERROGATORY # 37

**Reference:**
[A/5/1]

**Interrogatory:**
Please provide a table for OPDC similar to that provided in EB-2018-0242, Ex. I/1/1(a), but including the application of the new Ex/ A/5/1.

**Response:**
Refer to Exhibit I, Tab 1, Schedule 11, part (a).

# SEC INTERROGATORY # 38

**Reference:**
[A/5/1]

**Interrogatory:**
Please provide two tables for OPDC similar to those provided in EB-2018-0242, Ex. I/1/3(a), but including the application of the new Ex/ A/5/1. Please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

**Response:**
Please refer to Exhibit I, Tab 1, Schedule 12, part (a) for the requested tables.

Details on the adjustment factors applied to the Year 11 figures are provided in Exhibit I, Tab 1, Schedule 9.

# SEC INTERROGATORY # 39

**Reference:**
[Ex. A, Attachment 5]

**Interrogatory:**
Please provide details of any material adjustments to the purchase price or other terms of the Share Purchase Agreement, either in accordance with its terms or otherwise, as a result of the delay in closing if the transaction is approved in 2019.

**Response:**
Please see Exhibit I, Tab 1, Schedule 1 part b).

# SEC INTERROGATORY # 40

**Reference:**
[Ex. A, Attachment 12]

**Interrogatory:**
With respect to the OPDC Financial Statements:

a. Please provide the 2018 audited financial statements of OPDC.

b. Page 3, 20. Please provide a detailed explanation for the 8.1% increase in Net PP&E in 2017, and the 18.6% increase in Net PP&E in 2016.

c. Page 24, 27. Please provide a full continuity statement for OEB Account 1576 from 2015 to date, and explain any additions to the account of more than $100,000 in any year.

d. Page 37. For each of the categories of operating expenses in Note 21, please identify the amount, if any, paid to Hydro One or any of its affiliates, and provide details of those payments.

**Response:**
a) OPDC's 2018 Financial Statements are provided at Exhibit I, Tab 4, Schedule 4 Attachment 1.

b)

**OPDC Increase in Net PP&E Analysis**

| *(in 000s)* | 2018 | 2017 | 2016 | 2015 |
|---|---|---|---|---|
| Net PP&E amounts *(excluding intangibles)* per audited FS | $ 31,333 | $ 30,230 | $ 27,969 | $ 23,586 |
| Net PP&E $ year over year increases | $ 1,103 | $ 2,261 | $ 4,383 | |
| *Net PP&E % year over year increases* | *3.6%* | *8.1%* | *18.6%* | |
| **Captial Description:** | | | | |
| New Westmount substation (system renewal & growth) | $ - | $ - | $ 2,631 | |
| Substation Upgrades | $ 155 | $ 644 | $ 189 | |
| Voltage conversion (poles and conductor upgrades) | $ 211 | $ 295 | $ 484 | |
| Poles, devices, hardware and conductor replacements | $ 799 | $ 912 | $ 1,102 | |
| Transformers | $ 132 | $ 312 | $ 226 | |
| Meter replacements | $ 137 | $ 80 | $ 55 | |
| System Expansions | $ 544 | $ 844 | $ 839 | |
| Distribution system service | $ 122 | $ 403 | $ - | |
| General plant | $ 143 | $ 51 | $ 10 | |
| CWIP - Construction work in Progress | $ 115 | $ - | $ 23 | |
| Accumulated Depreciation | $ (1,196) | $ (1,154) | $ (1,099) | |
| Net Fixed Asset Disposals | $ (59) | $ (126) | $ (77) | |
| | **$ 1,103** | **$ 2,261** | **$ 4,383** | |

c)

| Continuity Schedule - Account 1576 | | | |
|---|---|---|---|
| **Year-end Closing Bal (000's)** | **Additions** | **Disposals** | **Balance per Audited Financial Statements** |
| Dec 2014 | | | 1,288 |
| Dec 2015 | 648 | - | 1,936 |
| Dec 2016 | 664 | (1,390) | 1,210 |
| Dec 2017 | 694 | (4) | 1,900 |
| Dec 2018 | 693 | - | **2,593** |

The following table shows the calculation of the differences in Amortisation arising as a result of changes made to accounting depreciation. These changes were a result of OPDC adopting new useful lives for capital assets based on the 2010 “Kinectric’s Report” effective January 1, 2013, as mandated by the OEB

| Calculation of Annual Additions to Account 1576 | | | |
|---|---|---|---|
| **Year ending** | **Amortization (Prior useful lives)** | **Amortization (Updated useful lives)** | **Differential Added To Deferral A/C 1576** |
| Dec 2015 | 1,740 | 1,092 | 648 |
| Dec 2016 | 1,742 | 1,078 | 664 |
| Dec 2017 | 1,806 | 1,112 | 694 |
| Dec 2018 | 1,833 | 1,140 | 693 |

d)

| Payments to Hydro One or its Affiliates | | | | |
|---|---|---|---|---|
| | | | | |
| | Financial Year | **2018** | **2017** | **2016** |
| **Operating Expenses as per Note to the Audited Financial Statements** | | **Note 18** | **Note 21** | **Note 21** |
| | | | **($000s)** | |
| | | | | |
| **Financial Statement Category** | Operations and Maintenance | **1,020** | **845** | **595** |
| | | | | |
| **Entity Name** | **Type of Service Provided** | | | |
| | | | | |
| Hydro One Networks Inc. | Charges for Joint Use Poles | **2** | **2** | **2** |
| | | | | |
| Hydro One Telecom Inc | Transparent Lan Service | **15** | **15** | **15** |

# SEC INTERROGATORY # 41

**Reference:**
[Ex. A, Attachment 16]

**Interrogatory:**
With respect to the Hydro One Distribution Financial Statements, please provide the same statements for the year ended December 31, 2018.

**Response:**
Please see Attachment 1 to this Schedule.

# HYDRO ONE NETWORKS INC.

## DISTRIBUTION BUSINESS

## FINANCIAL STATEMENTS

**DECEMBER 31, 2018**

# INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

*Opinion*

We have audited the carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve out balance sheet as at December 31, 2018
- the carve out statement of operations and comprehensive income for the year then ended
- the carve out statement of cash flows for the year then ended
- and notes to the carve out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "carve-out financial statements").

In our opinion, the accompanying carve-out financial statements as at and for the year ended December 31, 2018 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these carve-out financial statements.

*Basis for Opinion*

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

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

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

*Emphasis of Matter - Basis of Preparation*

We draw attention to Note 2 to the carve-out financial statements which describes the basis of preparation used in these carve-out financial statements.

The purpose of the carve-out financial statements is to meet Hydro One Networks Inc.'s obligation to the Ontario Energy Board. As a result, these carve-out financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

*Responsibilities of Management and Those Charged with Governance for the Carve-Out Financial Statements*

Management is responsible for the preparation of the carve-out financial statements in accordance with the financial reporting framework described in Note 2 in the carve-out financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

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

*Auditors' Responsibilities for the Audit of the Carve-Out Financial Statements*

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

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

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

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

We also:

- Identify and assess the risks of material misstatement of the carve-out financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors’ report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors’ report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the carve-out financial statements, including the disclosures, and whether the carve-out financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 25, 2019

# STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

**For the years ended December 31, 2018 and 2017**

| Year ended December 31 *(millions of Canadian dollars)* | 2018 | 2017 |
|---|---|---|
| **Revenues** | | |
| Energy sales | 4,078 | 4,005 |
| Rural rate protection *(Note 22)* | 239 | 247 |
| Other | 52 | 63 |
| | 4,369 | 4,315 |
| **Costs** | | |
| Purchased power *(Note 22)* | 2,900 | 2,875 |
| Operation, maintenance and administration *(Note 22)* | 568 | 567 |
| Depreciation, amortization and asset removal costs *(Note 4)* | 396 | 388 |
| | 3,864 | 3,830 |
| **Income before financing charges and income taxes** | **505** | **485** |
| Financing charges *(Notes 5, 22)* | 174 | 165 |
| **Income before income taxes** | **331** | **320** |
| Income taxes *(Note 6)* | 50 | 55 |
| **Net income** | **281** | **265** |
| Other comprehensive income | — | — |
| **Comprehensive income** | **281** | **265** |

*See accompanying notes to Financial Statements.*

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION BUSINESS**
**BALANCE SHEETS**
**At December 31, 2018 and 2017**

| December 31 *(millions of Canadian dollars)* | 2018 | 2017 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Accounts receivable *(Note 7)* | 578 | 588 |
| Due from related parties *(Note 22)* | 125 | 119 |
| Other current assets *(Note 8)* | 34 | 38 |
| | 737 | 745 |
| Property, plant and equipment *(Note 9)* | 7,511 | 7,324 |
| Other long-term assets: | | |
| Regulatory assets *(Note 11)* | 204 | 638 |
| Intangible assets *(Note 10)* | 309 | 289 |
| Goodwill | 168 | 168 |
| Other assets | — | 1 |
| | 681 | 1,096 |
| **Total assets** | **8,929** | **9,165** |
| **Liabilities** | | |
| Current liabilities: | | |
| Inter-company demand facility *(Note 22)* | 392 | 213 |
| Long-term debt payable within one year *(Notes 14, 15, 22)* | 291 | 337 |
| Accounts payable and other current liabilities *(Note 12)* | 720 | 679 |
| Due to related parties *(Note 22)* | 84 | 153 |
| | 1,487 | 1,382 |
| Long-term liabilities: | | |
| Long-term debt *(Notes 14, 15, 22)* | 3,620 | 3,498 |
| Deferred income tax liabilities *(Note 6)* | 33 | 499 |
| Regulatory liabilities *(Note 11)* | 217 | 84 |
| Other long-term liabilities *(Note 13)* | 856 | 934 |
| | 4,726 | 5,015 |
| **Total liabilities** | **6,213** | **6,397** |
| *Contingencies and Commitments (Notes 24, 25)* | | |
| *Subsequent Events (Note 26)* | | |
| Excess of assets over liabilities *(Notes 16, 20)* | 2,716 | 2,768 |
| **Total liabilities and excess of assets over liabilities** | **8,929** | **9,165** |

*See accompanying notes to Financial Statements.*

On behalf of the Board of Directors:

William Sheffield
Chair, Audit Committee

Russel Robertson
Director

**HYDRO ONE NETWORKS INC.**
**DISTRIBUTION BUSINESS**
**STATEMENTS OF CASH FLOWS**
**For the years ended December 31, 2018 and 2017**

| Year ended December 31 *(millions of Canadian dollars)* | 2018 | 2017 |
|---|---|---|
| **Operating activities** | | |
| Net income | 281 | 265 |
| Environmental expenditures | (15) | (15) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization *(Note 4)* | 345 | 337 |
| Regulatory assets and liabilities | 53 | 172 |
| Deferred income taxes | (15) | (44) |
| Other | 6 | 5 |
| Changes in non-cash balances related to operations *(Note 23)* | (27) | 173 |
| **Net cash from operating activities** | **628** | **893** |
| | | |
| **Financing activities** | | |
| Long-term debt issued | 412 | — |
| Long-term debt repaid | (337) | (195) |
| Payments to finance dividends and return on stated capital | (333) | (263) |
| Change in inter-company demand facility | 177 | 138 |
| Other | (2) | — |
| **Net cash used in financing activities** | **(83)** | **(320)** |
| | | |
| **Investing activities** | | |
| Capital expenditures *(Note 23)* | | |
| Property, plant and equipment | (483) | (522) |
| Intangible assets | (75) | (56) |
| Other | 13 | (4) |
| **Net cash used in investing activities** | **(545)** | **(582)** |
| | | |
| **Net change in cash and cash equivalents** | — | (9) |
| Cash and cash equivalents, beginning of year | — | 9 |
| **Cash and cash equivalents, end of year** | **—** | **—** |

*See accompanying notes to Financial Statements.*

## 1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One. The Company owns and operates regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

### Rate Setting

OEB March 7, 2019 Decisions

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). As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 11 - Regulatory Assets and Liabilities.

Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. The revenue requirements of $1,459 million for 2018, $1,498 million for 2019, $1,532 million for 2020, $1,578 million for 2021, and $1,624 million for 2022 were based on the OEB decision received on March 7, 2019. See Note 26(C) - 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.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with US GAAP, with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2018 have been prepared and are publicly available.

### Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company’s Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company’s long-term debt is allocated based on the respective borrowing requirements of the Company’s transmission and distribution businesses. A portion of the Company’s shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. These Financial Statements include deferred taxes and related regulatory balances 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. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 25, 2019, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 26 - Subsequent Events.

**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, post-retirement and post-employment benefits, asset retirement obligations, asset impairments, contingencies, 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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Transmission Business 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 Distribution Business 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.

**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.

<u>Nature of Revenues</u>

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. Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. 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 Distribution Business' best estimate of losses on billed accounts receivable balances. The Distribution Business 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.

**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 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 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.

The Distribution Business records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

**Inter-company Demand Facility**

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

**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 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 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.

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.

**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 Distribution Business' 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 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 review resulted in changes to rates effective January 1, 2015 for Hydro One Networks' distribution business. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

| | Average | Rate | |
|---|---|---|---|
| | Service Life | Range | Average |
| Property, plant and equipment: | | | |
| Distribution | 47 years | 1% - 7% | 2% |
| Communication | 8 years | 1% - 15% | 12% |
| Administration and service | 20 years | 1% - 20% | 5% |
| 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.

The carrying costs of most of the Distribution Business' 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. As at December 31, 2018 and 2017, no asset impairment had been recorded.

**Costs of Arranging Debt Financing**

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the 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 other comprehensive income (OCI). OCI and net income are presented in a single continuous 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 15 - Fair Value of Financial Instruments and Risk Management.

**Derivative Instruments and Hedge Accounting**

Hydro One 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. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

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 Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its 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 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 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 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. Hydro One 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. Hydro One 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 Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One 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

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in AOCI. 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.

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 Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited 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 the 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' 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 Distribution Business 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 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 Distribution Business.

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. The Distribution Business 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 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 Distribution Business 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 Distribution Business' 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 Networks:

**Recently Adopted Accounting Guidance**

| Guidance | Date issued | Description | Effective date | Impact |
|---|---|---|---|---|
| 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, the Company 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 | The Company 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 11 - Regulatory Assets and Liabilities. |

### Recently Issued Accounting Guidance Not Yet Adopted

| Guidance | Date issued | Description | Effective date | Anticipated impact |
|---|---|---|---|---|
| 2016-02<br>2018-01<br>2018-10<br>2018-11<br>2018-20<br>2019-01 | February 2016 – March 2019 | 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. ASU 2019-01 provides clarification on three issues: determining the fair value of the underlying assets by lessors that are not manufacturers or dealers, presentation of statement of cash flows for sales-type and direct financing leases and interim transition disclosures relating to Topic 250, Accounting Changes and Error Corrections. | January 1, 2019 | The Distribution Business 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 Distribution Business 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 Distribution Business will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to the Distribution Business' financial statements will be the recognition of approximately $12 million of Right-of-Use (ROU) assets and corresponding lease obligations on the Balance Sheet. The ROU assets and lease obligations represent the present value of the Distribution Business' 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 Hydro One's incremental borrowing rate. |
| 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. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Depreciation of property, plant and equipment | 278 | 278 |
| Amortization of intangible assets | 52 | 44 |
| Amortization of regulatory assets | 15 | 15 |
| Depreciation and amortization | 345 | 337 |
| Asset removal costs | 51 | 51 |
| | 396 | 388 |

## 5. FINANCING CHARGES

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Interest on long-term debt *(Note 22)* | 168 | 170 |
| Interest on inter-company demand facility *(Note 22)* | 4 | 2 |
| Other | 10 | 4 |
| Less: Interest capitalized on construction and development in progress | (8) | (11) |
| | 174 | 165 |

## 6. INCOME TAXES

As a rate regulated utility business, the Distribution Business'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 | 331 | 320 |
| Income taxes at statutory rate of 26.5% (2017 - 26.5%) | 88 | 85 |
| Increase (decrease) resulting from: | | |
| Net temporary differences recoverable in future rates charged to customers: | | |
| Capital cost allowance in excess of depreciation and amortization | (20) | (15) |
| Overheads capitalized for accounting but deducted for tax purposes | (7) | (7) |
| Pension contributions in excess of pension expense | (5) | (6) |
| Environmental expenditures | (4) | (4) |
| Interest capitalized for accounting but deducted for tax purposes | (2) | (3) |
| Other | (1) | 4 |
| Net temporary differences | (39) | (31) |
| Net permanent differences | 1 | 1 |
| Total income taxes | 50 | 55 |
| Effective income tax rate | 15.1% | 17.2% |

The major components of income tax expense are as follows:

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Current income taxes | 65 | 99 |
| Deferred income taxes (recovery) | (15) | (44) |
| Total income taxes | 50 | 55 |

### 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 (liabilities)** | | |
| Capital cost allowance in excess of depreciation and amortization | (362) | (808) |
| Goodwill | (10) | (10) |
| Post-retirement and post-employment benefits expense in excess of cash payments | 291 | 311 |
| Regulatory amounts that are not recognized for tax purposes | 32 | (17) |
| Environmental expenditures | 22 | 30 |
| Non-capital losses | 1 | 1 |
| Other | (7) | (6) |
| Net deferred income tax liabilities | (33) | (499) |

The net deferred income tax liabilities are presented on the Balance Sheets as long-term liabilities.

## 7. ACCOUNTS RECEIVABLE

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Accounts receivable – billed | 262 | 276 |
| Accounts receivable – unbilled | 336 | 341 |
| Accounts receivable, gross | 598 | 617 |
| Allowance for doubtful accounts | (20) | (29) |
| Accounts receivable, net | 578 | 588 |

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 | 26 | 25 |
| Additions to allowance for doubtful accounts | (17) | (19) |
| Allowance for doubtful accounts – ending | (20) | (29) |

## 8. OTHER CURRENT ASSETS

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Regulatory assets *(Note 11)* | 18 | 22 |
| Prepaid expenses and other assets | 11 | 12 |
| Materials and supplies | 5 | 4 |
| | 34 | 38 |

## 9. PROPERTY, PLANT AND EQUIPMENT

| December 31, 2018 *(millions of dollars)* | Property, Plant and Equipment[1] | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Distribution | 10,518 | 3,538 | 74 | 7,054 |
| Communication | 144 | 112 | — | 32 |
| Administration and service | 975 | 583 | 25 | 417 |
| Easements | 12 | 4 | — | 8 |
| | 11,649 | 4,237 | 99 | 7,511 |

[1] Includes future use assets totalling $50 million.

| December 31, 2017 *(millions of dollars)* | Property, Plant and Equipment[1] | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| Distribution | 10,155 | 3,488 | 147 | 6,814 |
| Communication | 145 | 99 | 2 | 48 |
| Administration and service | 991 | 561 | 25 | 455 |
| Easements | 11 | 4 | — | 7 |
| | 11,302 | 4,152 | 174 | 7,324 |

[1] Includes future use assets totalling $57 million.

Financing charges capitalized on property, plant and equipment under construction were $5 million in 2018 (2017 - $9 million).

## 10. INTANGIBLE ASSETS

| December 31, 2018 *(millions of dollars)* | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 492 | 247 | 30 | 275 |
| Other | 52 | 18 | — | 34 |
| | 544 | 265 | 30 | 309 |

| December 31, 2017 *(millions of dollars)* | Intangible Assets | Accumulated Amortization | Development in Progress | Total |
|---|---|---|---|---|
| Computer applications software | 428 | 201 | 23 | 250 |
| Other | 49 | 12 | 2 | 39 |
| | 477 | 213 | 25 | 289 |

Financing charges capitalized to intangible assets under development were $1 million in 2018 (2017 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2019 - $51 million; 2020 - $42 million; 2021 - $41 million; 2022 - $40 million; and 2023 - $31 million.

## 11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| **Regulatory assets:** | | |
| Deferred income tax regulatory asset | 96 | 513 |
| Environmental | 61 | 83 |
| Stock-based compensation | 21 | 20 |
| Post-retirement and post-employment benefits non-service cost | 16 | — |
| Distribution system code exemption | 10 | 10 |
| Post-retirement and post-employment benefits | — | 20 |
| Other | 18 | 14 |
| Total regulatory assets | 222 | 660 |
| Less: current portion | (18) | (22) |
| | 204 | 638 |
| **Regulatory liabilities:** | | |
| Post-retirement and post-employment benefits | 73 | — |
| Green Energy expenditure variance | 52 | 60 |
| Retail settlement variance account | 39 | — |
| Pension cost differential | 38 | 13 |
| Deferred income tax regulatory liability | 33 | — |
| 2015-2017 rate rider | 6 | 6 |
| PST savings deferral | 4 | 4 |
| Other | 13 | 12 |
| Total regulatory liabilities | 258 | 95 |
| Less: current portion | (41) | (11) |
| | 217 | 84 |

### 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 Distribution Business 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 Distribution Business' 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 $331 million (2017 - higher by $38 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 Limited 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 these decisions, the Distribution Business has recognized a reduction in Hydro One Networks' distribution deferred income tax regulatory asset of $473 million, an increase in deferred income tax regulatory liability of $33 million, and a decrease in deferred tax liability of $506 million. Notwithstanding the recognition of the effects of the decision in the 2018 financial statements, on April 5, 2019, the Company filed an appeal with the Ontario Divisional Court with respect to the OEB's deferred tax benefit decision.

**Environmental**

The Distribution Business 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 In 2018, the environmental regulatory asset decreased by $10 million (2017 - $1 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 prudency and the timing of recovery of all of the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been lower by $10 million (2017 - $1 million). In addition, 2018 amortization expense would have been lower by $15 million (2017 - $15 million), and 2018 financing charges would have been higher by $3 million (2017 - $4 million).

**Post-Retirement and Post-Employment Benefits - Non-Service Cost**

Hydro One Networks 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 March 2019, the OEB approved the regulatory asset for Hydro One Networks' Distribution Business. Hydro One Networks 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.

**Stock-based Compensation**

The Distribution Business 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 - $4 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 Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the 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 $93 million (2017 - $116 million).

**Pension Cost Differential**

A pension cost differential account was established for Hydro One Networks' Distribution Businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The Distribution Business 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 $25 million (2017 - $21 million).

**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.

**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

**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 on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

**PST Savings Deferral Account**

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration expenses or capital expenditures for past revenue requirements approved during a full cost-of-service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administration expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable, and calculations for tracking and refund were requested by the OEB. For Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider.

## 12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Accrued liabilities | 588 | 562 |
| Accounts payable | 53 | 66 |
| Accrued interest *(Note 22)* | 38 | 40 |
| Regulatory liabilities *(Note 11)* | 41 | 11 |
| | 720 | 679 |

## 13. OTHER LONG-TERM LIABILITIES

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Post-retirement and post-employment benefit liability *(Note 17)* | 781 | 838 |
| Environmental liabilities *(Note 18)* | 48 | 66 |
| Long-term inter-company payable *(Note 22)* | 17 | 18 |
| Long-term accounts payable and other liabilities | 5 | 8 |
| Asset retirement obligations *(Note 19)* | 5 | 4 |
| | 856 | 934 |

## 14. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Distribution Business outstanding at December 31, 2018 and 2017:

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Long-term debt | 3,921 | 3,846 |
| Add: Net unamortized debt premiums | 7 | 8 |
| Add: Unrealized mark-to-market gain[1] | (2) | (4) |
| Less: Deferred debt issuance costs | (15) | (15) |
| Less: Long-term debt payable within one year | (291) | (337) |
| Long-term debt | 3,620 | 3,498 |

[1] The unrealized mark-to-market net gain relates to $30 million of notes due in 2020 and $200 million notes due in 2019. The unrealized mark-to-market net gain is offset by a $2 million (2017 - $4 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.

In 2018, Hydro One issued $1,400 million (2017 - $nil) of long-term debt under its MTN Program, all of which was mirrored down to Hydro One Networks, and $412 million was allocated to the Company's Distribution Business.

In 2018, Hydro One repaid $750 million (2017 - $600 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $750 million (2017 - $600 million) to Hydro One, of which $337 million (2017 - $195 million) was allocated to the Company's Distribution Business.

### 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 | 291 | 167 | 2.0 |
| 2020 | 150 | 160 | 3.9 |
| 2021 | 250 | 154 | 2.1 |
| 2022 | 261 | 148 | 3.2 |
| 2023 | — | 143 | — |
| | 952 | 772 | 2.7 |
| 2024-2028 | 376 | 684 | 3.1 |
| 2029 and thereafter | 2,593 | 1,691 | 5.1 |
| | 3,921 | 3,147 | 4.3 |

## 15. 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.

The Company 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 Networks 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 carrying amounts of accounts receivable, due from related parties, inter-company demand facility, 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 Distribution Business' 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 |
|---|---|---|---|---|
| $200 million notes due 2019 | 198 | 198 | 197 | 197 |
| $30 million notes due 2020 | 30 | 30 | 29 | 29 |
| Other notes and debentures | 3,683 | 4,028 | 3,609 | 4,159 |
| Long-term debt, including current portion | 3,911 | 4,256 | 3,835 | 4,385 |

### Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

At December 31, 2018, the Distribution Business' share of the Company's derivative instruments included $230 million (2017 - $230 million) interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was approximately 6% (2017 - 6%) of its total long-term debt. At December 31, 2018, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- a $200 million fixed-to-floating interest-rate swap agreement to convert $200 million notes maturing on November 18, 2019 into three-month variable rate debt; and
- a $30 million fixed-to-floating interest-rate swap agreement to convert $30 million of the $350 million notes maturing on April 30, 2020 into three-month variable rate debt.

At December 31, 2018 and 2017, the Company had no interest-rate swaps classified as undesignated contracts.

### 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 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 392 | 392 | 392 | — | — |
| Long-term debt, including current portion | 3,911 | 4,256 | — | 4,256 | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 2 | 2 | — | 2 | — |
| | 4,305 | 4,650 | 392 | 4,258 | — |

| December 31, 2017 *(millions of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Inter-company demand facility | 213 | 213 | 213 | — | — |
| Long-term debt, including current portion | 3,835 | 4,385 | — | 4,385 | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 4 | 4 | — | 4 | — |
| | 4,052 | 4,602 | 213 | 4,389 | — |

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.

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 or material foreign exchange 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 Distribution Business' net income for the years ended December 31, 2018 and 2017.

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 Statements of Operations and Comprehensive Income. The Distribution Business' 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 Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business 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 $20 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 Distribution Business' 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. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on the 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 Networks meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund normal operating requirements.

## 16. CAPITAL MANAGEMENT

The Distribution Business' 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. At December 31, 2018 and 2017, the Distribution Business' capital structure was as follows:

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Long-term debt payable within one year | 291 | 337 |
| Inter-company demand facility | 392 | 213 |
| | 683 | 550 |
| Long-term debt | 3,620 | 3,498 |
| Excess of assets over liabilities | 2,716 | 2,768 |
| **Total capital** | 7,019 | 6,816 |

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2018 and 2017:

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Excess of assets over liabilities - beginning | 2,768 | 2,766 |
| Net income | 281 | 265 |
| Payments to Hydro One to finance dividends and return of stated capital | (333) | (263) |
| **Excess of assets over liabilities - ending** | 2,716 | 2,768 |

## 17. 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. The Distribution Business contributions to the DC Plan for the year ended December 31, 2018 were less than $1 million (2017 - less than $1 million).

### Pension Plan and Supplemental Plan

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.

At December 31, 2018, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,752 million (2017 - $8,258 million). The fair value of pension plan assets available for these benefits was $7,205 million (2017 - $7,277 million).

### Post-Retirement and Post-Employment Plans

During the year ended December 31, 2018, the Distribution Business charged $33 million (2017 - $35 million) of post-retirement and post-employment benefit costs to operation, and capitalized $31 million (2017 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2018 were $27 million (2017 - $24 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $93 million (2017 - $116 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Accrued liabilities | 27 | 26 |
| Post-retirement and post-employment benefit liability | 781 | 838 |
| Net unfunded status | 808 | 864 |

## 18. 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 | 61 | 22 | 83 |
| Interest accretion | 2 | 1 | 3 |
| Expenditures | (10) | (5) | (15) |
| Revaluation adjustment | (8) | (2) | (10) |
| Environmental liabilities - ending | 45 | 16 | 61 |
| Less: current portion | (9) | (4) | (13) |
| | 36 | 12 | 48 |

| Year ended December 31, 2017 *(millions of dollars)* | PCB | LAR | Total |
|---|---|---|---|
| Environmental liabilities - beginning | 66 | 29 | 95 |
| Interest accretion | 3 | 1 | 4 |
| Expenditures | (10) | (5) | (15) |
| Revaluation adjustment | 2 | (3) | (1) |
| Environmental liabilities - ending | 61 | 22 | 83 |
| Less: current portion | (12) | (5) | (17) |
| | 49 | 17 | 66 |

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheets after factoring in the discount rate:

| December 31, 2018 *(millions of dollars)* | PCB | LAR | Total |
|---|---|---|---|
| Undiscounted environmental liabilities | 49 | 16 | 65 |
| Less: discounting environmental liabilities to present value | (4) | — | (4) |
| Discounted environmental liabilities | 45 | 16 | 61 |

| December 31, 2017 *(millions of dollars)* | PCB | LAR | Total |
|---|---|---|---|
| Undiscounted environmental liabilities | 64 | 23 | 87 |
| Less: discounting environmental liabilities to present value | (3) | (1) | (4) |
| Discounted environmental liabilities | 61 | 22 | 83 |

At December 31, 2018, the estimated future environmental expenditures were as follows:

| *(millions of dollars)* | |
|---|---|
| 2019 | 14 |
| 2020 | 16 |
| 2021 | 13 |
| 2022 | 11 |
| 2023 | 10 |
| Thereafter | 1 |
| | 65 |

The Distribution Business 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 Distribution Business' 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.

**PCB**

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 PCBs in concentrations of less than 2 ppm.

The Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $49 million (2017 - $64 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2018 to decrease the PCB environmental liability by $8 million (2017 - increase by $2 million).

**LAR**

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program is $16 million (2017 - $22 million). These expenditures are expected to be incurred over the period from 2018 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2018 to decrease the LAR environmental liability by $2 million (2017 - $3 million).

## 19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks 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 Distribution Business' 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 for the Distribution Business by $1 million (2017 - $nil).

At December 31, 2018, Hydro One Networks had recorded asset retirement obligations of $5 million (2017 - $4 million) related to its Distribution Business, 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.

## 20. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2018 and 2017, Hydro One Networks had 207,557,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2018, Hydro One Networks declared common share dividends in the amount of $1 million (2017 - $2 million) and made a return of stated capital of $545 million (2017 – $509 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends and return of stated capital was $333 million (2017 - $263 million).

## 21. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

### Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (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). Hydro One and Hydro One Limited entered into an inter-company agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 million. The fair value was estimated based on the grant date Hydro One Limited 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, 248,109 common shares were issued under the Share Grant Plans (2017 - 186,489) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2018 was $6 million (2017 - $8 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' 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 | 2,599,170 | $20.50 |
| Vested and issued[1] | (248,109) | — |
| Forfeited | (55,187) | $20.50 |
| Share grants outstanding - ending | 2,295,874 | $20.50 |

[1] In 2018,Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

| Year ended December 31, 2017 | Share Grants *(number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding - beginning | 2,853,079 | $20.50 |
| Vested and issued[1] | (186,489) | |
| Forfeited | (67,420) | $20.50 |
| Share grants outstanding - ending | 2,599,170 | $20.50 |

[1] In 2017, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks employees in accordance with provisions of the PWU Share Grant Plan. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

**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 Limited 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 Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2018 and 2017, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

| Year ended December 31 *(number of DSUs)* | 2018 | 2017 |
|---|---|---|
| DSUs outstanding - beginning | 74,268 | 53,481 |
| Granted | 19,457 | 20,787 |
| Settled | (52,618) | — |
| DSUs outstanding - ending | 41,107 | 74,268 |

For the year ended December 31, 2018, an expense of $nil (2017 - $nil) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2018, a liability of $nil (2017 - $1 million) related to Directors' DSUs has been recorded at the December 31, 2018 closing price of Hydro One Limited 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 Hydro One Limited common shares of $20.04, with an amount of approximately $1 million paid in 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 Hydro One Limited 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 Limited Board of Directors.

During 2018 and 2017, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

| Year ended December 31 *(number of DSUs)* | 2018 | 2017 |
|---|---|---|
| DSUs outstanding - beginning | 25,162 | — |
| Granted | 8,740 | 25,601 |
| Paid | — | (439) |
| DSUs outstanding - ending | 33,902 | 25,162 |

For the year ended December 31, 2018, an expense recognized in earnings by the Distribution Business with respect to the Management DSU Plan was $nil (2017 - $1 million). At December 31, 2018, a liability related to outstanding DSUs recorded at the closing price of Hydro One Limited common shares of $20.25 and included in long-term accounts payable and other liabilities on the Balance Sheets was $nil (2017 - $1 million).

**Employee Share Ownership Plan**

In 2015, Hydro One Limited 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 Limited. 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 Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2018, Company contributions made under the ESOP for the Distribution Business were $1 million (2017 - $1 million).

**LTIP**

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited 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 Limited.

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

During 2018 and 2017, LTIP awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

| | PSUs | | RSUs | |
|---|---|---|---|---|
| Year ended December 31 *(number of units)* | 2018 | 2017 | 2018 | 2017 |
| Units outstanding – beginning | 168,490 | 74,063 | 151,490 | 83,394 |
| Granted | 128,364 | 118,467 | 97,207 | 96,697 |
| Vested and issued[1] | (56) | (276) | (45,139) | (7,054) |
| Forfeited | (13,656) | (23,764) | (13,184) | (21,547) |
| Settled | (51,010) | — | (34,159) | — |
| Units outstanding – ending | 232,132 | 168,490 | 156,215 | 151,490 |

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Networks Transmission Business employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

The grant date total fair value of the awards granted in 2018 was $5 million (2017 - $5 million). The compensation expense related to the PSU and RSU awards recognized by the Distribution Business during 2018 was $4 million (2017 - $2 million). The expense recognized in 2018 included less than $1 million related to previously awarded PSUs and RSUs to Hydro One's former President and CEO for which costs had not previously been recognized. These awards were settled in 2018 through a one-time cash settlement arrangement.

At December 31, 2018, $4 million (2017 - $3 million) payable relating to PSU and RSU awards was included in due to related parties on the Balance Sheets.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, Hydro One Limited 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 Limited common share price on the date of the grant.
[2] Based on dividend and Hydro One Limited common share price on the date of the grant.
[3] Based on average daily volatility of Hydro One Limited's 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.

During 2018 and 2017, the activity of stock options granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

| **Year ended December 31** *(number of stock options)* | 2018 | 2017 |
|---|---|---|
| Stock options outstanding - beginning | — | — |
| Granted[1] | 391,118 | — |
| Cancelled[2] | (54,604) | — |
| Stock options outstanding - ending[1] | 336,514 | — |

[1] All stock options granted and outstanding at December 31, 2018 are non-vested.
[2] During 2018, stock options previously awarded to the Company's former President and CEO were cancelled. The Hydro One Networks unrecognized compensation expense related to the cancelled stock options was not significant.

The compensation expense related to stock options recognized by the Company during 2018 was not significant.

## 22. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2018. The IESO, Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province.

Year ended December 31 *(millions of dollars)*

| Related Party | Transaction | 2018 | 2017 |
|---|---|---|---|
| **IESO** | Power purchased | 1,636 | 1,583 |
| | Amounts related to electricity rebates | 475 | 357 |
| | Distribution revenues related to rural rate protection | 239 | 247 |
| | Funding received related to Conservation and Demand Management programs | 62 | 59 |
| **OPG** | Power purchased | 10 | 9 |
| | Revenues related to supply of electricity | 6 | 5 |
| **OEFC** | Power purchased from power contracts administered by the OEFC | 2 | 2 |
| **OEB** | OEB fees | 4 | 5 |
| **Hydro One Limited and its subsidiaries** | Revenues for services provided | 2 | 1 |
| | Services received - costs expensed | 12 | 16 |
| | Interest expense on long-term debt | 168 | 170 |
| | Interest expense on inter-company demand facility | 4 | 2 |
| | Payments to finance dividends and return of stated capital | 333 | 263 |
| | Stock-based compensation costs | 10 | 10 |

The amounts due to and from related parties at December 31, 2018 and 2017 are as follows:

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Inter-company demand facility | (392) | (213) |
| Due from related parties | 125 | 119 |
| Due to related parties | (84) | (153) |
| Accrued interest | (38) | (40) |
| Long-term inter-company payable | (17) | (18) |
| Long-term debt, including current portion | (3,911) | (3,835) |

## 23. 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 | 10 | 198 |
| Due from related parties | (6) | (86) |
| Materials and supplies | (1) | — |
| Other assets | 2 | 4 |
| Accounts payable | (10) | 10 |
| Accrued liabilities | 29 | 32 |
| Due to related parties | (68) | (25) |
| Accrued interest | (2) | (2) |
| Long-term accounts payable and other liabilities | (1) | (6) |
| Post-retirement and post-employment benefit liability | 20 | 48 |
| | (27) | 173 |

### Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the Statements of Cash Flows for the years ended December 31, 2018 and 2017. The reconciling items include change in accruals and capitalized depreciation.

| Year ended December 31, 2018 *(millions of dollars)* | Property, Plant and Equipment | Intangible Assets | Total |
|---|---|---|---|
| Capital investments | (497) | (76) | (573) |
| Reconciling items | 14 | 1 | 15 |
| Cash outflow for capital expenditures | (483) | (75) | (558) |

| Year ended December 31, 2017 *(millions of dollars)* | Property, Plant and Equipment | Intangible Assets | Total |
|---|---|---|---|
| Capital investments | (537) | (48) | (585) |
| Reconciling items | 15 | (8) | 7 |
| Cash outflow for capital expenditures | (522) | (56) | (578) |

### Supplementary Information

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Net interest paid | 170 | 172 |
| Income taxes paid | 70 | 16 |

## 24. CONTINGENCIES

Hydro One Networks 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 financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, 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. The plaintiff's application for leave to appeal was denied by the Ontario Court of Appeal in March 2019, which means that the lawsuit has effectively ended.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

## 25. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

## 26. SUBSEQUENT EVENTS

### (A) Payments to Finance Dividends and Return of Stated Capital

On February 20, 2019, Hydro One Networks declared common share dividends of $1 million, and a return of stated capital of $138 million was approved. The amount allocated to the Distribution Business to finance these payments was $93 million.

### (B) Stock-based Compensation

Subsequent to December 31, 2018, Hydro One Limited issued from treasury 20,949 and 207,737 common shares to eligible Distribution Business employees in accordance with provisions of the LTIP and Share Grant Plans, respectively.

**(C) 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. As a result, the financial impact of this OEB decision has been reflected in these financial statements, as more fully discussed in Note 11 - 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 11 - 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.

**(D) Long-term Debt**

On April 5, 2019, Hydro One issued the following long-term debt under its MTN Program:

- $700 million notes with a maturity date of April 5, 2024 and a coupon rate of 2.54%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 2.79%, of which $287 million was allocated to the Distribution Business;
- $550 million notes with a maturity date of April 5, 2029 and a coupon rate of 3.02%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.27%, of which $225 million was allocated to the Distribution Business; and
- $250 million notes with a maturity date of April 5, 2050 and a coupon rate of 3.64%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.89%, of which 103 million was allocated to the Distribution Business.

On March 21, 2019, Hydro One repaid $228 million of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $228 million to Hydro One, of which $91 million was allocated to the Distribution Business.

# ENERGY PROBE INTERROGATORY # 1

**Reference:**

Exhibit A, Tab 1, Schedule 1, page 4, and Exhibit A, Tab 4, Schedule 1, Page 11

**Interrogatory:**

**Preamble:** "The Purchaser shall establish an advisory committee (the "Advisory Committee") to provide a forum for communication between the Purchaser and the community;"

**Question:**

a) Has the advisory committee been established? If the answer is yes, please provide the date of its establishment and the names of the committee members. If the answer is no please explain why not.

b) How was the public informed of the proposed merger?

c) Please file copies of documents that were sent to ratepayers informing them of the proposed merger.

d) How was public input solicited?

e) Were any public meetings held? If the answer is yes please provide information on the meeting(s), including date, location, attendance, and meeting summaries prepared by staff employed by Applicants or their representatives.

f) How was the public informed of the EB-2016-0276 and the EB-2017-0320 decisions? Please file copies of any documents that may have been sent to ratepayers informing them of the decisions.

g) It appears from public comments on the record in this proceeding that there is significant opposition to the merger. Please explain the reasons for this opposition as Hydro One understands them.

**Response:**

a) No, the advisory committee has not been established. As per section 6.3 of the Share Purchase Agreement, the Advisory Committee will be established post-closing.

b) It should first be clarified that this transaction is a share sale and not a merger. On August 15, 2016, Mayor Steve Clarke announced that the City of Orillia had reached agreements with Hydro One to sell the distribution assets of the Orillia Power Corporation (OPC), being its shares in OPDC, to Hydro One pending Ontario Energy Board approval.

c) Please see Attachment 1 for a copy of an OPC Bill insert and Attachment 2 for the Orillia Packet and Times newspaper wrap both made public in September, 2016.

d) This question is not relevant to the OEB's application of the "no harm" test.

In the Norfolk Power Distribution Inc. ("Norfolk") MAADs proceeding (EB-2013-0187/0196/0198), the Board clearly found that the process of a seller leading up to a LDC transaction is not relevant to the "no harm" test and that the "no harm" test looks at the effect of a transaction, not the reason for or the process preceding the transaction. The Board determined as follows:

> "As indicated in the Combined Proceeding, the Board also considers that the conduct or motivations of a seller leading up to the consolidation transaction are not relevant to the "no harm" test. The "no harm" test looks at the effect of a transaction, not the reason for or the process preceding the transaction. Accordingly, the Board does not consider IRs relating to the overall merits or rationale for HONI's acquisition plans, including any related communications with government, to be relevant to this proceeding." [Norfolk MAADs Proceeding (EB-2013-0187/0196/0198), Decision and Order and Procedural Order No. 8, January 24, 2014, at Page 5]

The Board established this approach in its Combined Proceeding (EB-2005-0234/0254/0257), in which it considered how it will review applications for leave to acquire shares or amalgamate under section 86 of the Ontario Energy Board Act, 1998, finding:

> "As a general matter, the conduct of the seller generally, including the extent of its due diligence or the degree of public consultation in relation to the transaction, would not be issues for the Board on share acquisition or amalgamation applications under section 86 of the Act. Based on the "no harm" test, the question for the Board is neither the why nor the how of the proposed transaction. Rather, the Board's concern is limited to the effect of the transaction when considered in light of the Board's objectives as identified in section 1 of the Act." [Combined Proceeding (EB-2005-0234/0254/0257), Decision, August 31, 2005, at Pages 8-9]

The Board went on to make the following finding in the Combined Decision:

> "With respect to the claim that ratepayers have a right to "an open and transparent process" for the sale of the shares or the assets of an electricity distributor, the Board has two observations. First, section 86 of the Act applies to distributors whether they are publicly or privately owned. Although the three Applications at issue involve utilities that are municipally-owned, not all distributors are publicly owned. As a result, any findings by the Board with respect to customers' process rights (in the sense of rights associated with the process leading up to the conclusion of a transaction) would apply to privately-owned companies. Further, the legislature has determined that distributors should be governed by the Ontario Business Corporations Act ("OBCA"). The OBCA contains provisions governing procedures and rights associated with, among other things, amalgamations and other significant corporate activities. Viewed from this perspective, the Board does not believe it is appropriate to open up corporate process issues to review. The Board does not believe it is appropriate to add an additional layer of corporate review by vesting process rights (again, in the sense of rights associated with the process leading up to the conclusion of a transaction) within customers of distribution companies. The content of such rights and the process by which they may be exercised is beyond the Board's objectives or role within the energy sector." [Combined Proceeding (EB-2005-0234/0254/0257), Decision, August 31, 2005, at Page 9]

The OEB is clear that the process preceding the transaction is not relevant in the Board's application of the “no harm” test.

e) Please refer to the response to d) above as this question also pertains to the process preceding the share sale transaction.

f) The public was informed of the decision on EB-2016-0276 via a news release April 12, 2018 (see Attachment 3). There were no public communications regarding the EB-2017-0320 decision.

g) Hydro One is aware that letters of comment opposing the proposed transaction have been filed in this proceeding, along with a number of letters in support of the transaction. The letters opposing the transaction appear to be mainly concerned with: (i) the financial impact on the City of Orillia on selling OPDC; (ii) the impact on electricity reliability when served by Hydro One; (iii) customer rates; (iv) the purchase price that the City agreed to sell the utility to Hydro One for; (v) the loss and pride of local ownership of OPDC; and (vi) the actions of Orillia City Council.

Hydro One notes that certain of the concerns raised in the letters opposing the transaction are relevant to the scope of the OEB’s “no harm test” and certain of the concerns are not. The balance of this response addresses only those with relevant aspects. With respect to reliability, Hydro One has made commitments throughout this application that confirm that customers are not expected to see any impact on the reliability of electricity supply as a result of the transaction. Hydro One will continue to maintain and operate the assets to serve the current service territory of OPDC to meet the same standards as were required by OPDC. With respect to customer rates, Hydro One has also made a number of commitments throughout this application to ensure and demonstrate that not only will customers not be harmed with respect to price as a result of the transaction but will in fact benefit from the transaction.

The letters supporting the transaction reference, as the basis for support (i) the lower rates that customers will receive both during and after the deferral period; (ii) the benefit of the cash proceedings to retire debt and invest in infrastructure in Orillia; (iii) the potential construction of the Integrated System Operating Centre and operating centres creating new construction jobs and new ongoing employment; (iv) Hydro One’s partnership with local post-secondary education institutions; and (v) the positive impact on an Orillia hospital arising from lower electricity rates allowing the saved funds to be redirected to improve patient care services.

Hydro One believes that the enthusiastic endorsement of the proposed transaction from the Mayor and Council, as duly elected representatives of the people of Orillia, is sufficient to demonstrate that there is public support for the proposed transaction. Further, the Mayor having been reelected in the Fall of 2018 as a vocal supporter of the proposed transaction lends additional credence to the understanding that the proposed transaction is a matter for which support has been demonstrated in the broadest of public forums.

Join us for one of two public meetings on Thursday, September 29, 2016, at the Orillia City Centre: 2-4 p.m. or 7-9 p.m.

# Community Investment Opportunity with Hydro One

ORILLIA INCORPORATED 1867

## How we got to where we are today

- September 2015 – Orillia Council announced it was entering into negotiations with Hydro One on an opportunity that would have Hydro One locating an Advanced Technology Hub in West Orillia and purchasing the Orillia Power Distribution Corporation.
- Council endorsed negotiations based on a set of principles.
- Council held two formal public consultations (January 2016 and June 2016) to enable the public to ask questions and provide comments.
- Mayor Clarke spoke to dozens of community groups about the opportunity and numerous ward meetings were held throughout the year with this topic being discussed.
- Council Members were briefed in detail about the transaction throughout the negotiations.
- Orillia Power Corporation Board of Directors voted in favour of the deal on Aug. 12, 2016.
- Council voted in favour of the deal and agreements were signed by the City of Orillia and Hydro One on Aug. 15, 2016.

"The Hydro One investment will contribute to Quality of Life in Orillia through the creation of local jobs and an increased tax base. It will attract skilled labour and offer growth for those members of the Orillia workforce seeking a foothold in a vibrant energy sector that will thrive in the community."

- MIKE TAYLOR, PRESIDENT MUSKOKA HALIBURTON ORILLIA – THE LAKELANDS ASSOCIATION OF REALTORS®

## Frequently Asked Questions

**What is Hydro One planning to build in Orillia?**
Hydro One intends, subject to Ontario Energy Board (OEB) approval, to build three facilities within the Horne Business Park in West Orillia.

- Back-up Ontario Grid Control Centre/Integrated Systems Operation Centre (ISOC) on 16.41 acres of land.
- Provincial Warehouse on 10 acres of land.
- Regional Operations Centre on 10 acres of land.

Hydro One has purchased 16.41 acres of land required to build the ISOC portion of the development for approximately $3 million – validated as fair market value by a third-party valuator. Construction of the buildings is estimated at more than $150 million. The construction of the ISOC will require an upgrade to fibre optics in the area.

*Control room at the Ontario Grid Control Centre.*

**What are the economic benefits of this deal to the City of Orillia?**
In the short term, the economic impact of the construction of the buildings and related activity is anticipated to inject $200 to $300 million into the Orillia economy. Once all the facilities are operational, employees at this Orillia facility are expected to receive a cumulative $30 million in payroll/incomes into the Orillia economy year over year. This will result in economic spin-offs through the creation of new jobs and additional spending in housing construction, retail, restaurants, personal services (i.e. dentists, taxis), schools and colleges, and many other fields throughout the Orillia economy.

**How will this deal affect my electricity rates?**
It is important to acknowledge that the infrastructure of Orillia Power will need upgrading over the next decade – a cost that would likely have driven Orillia Power distribution rates up by almost 10% over the next number of years. Upon closing, which requires Ontario Energy Board approval, Hydro One will lower distribution rates by 1% and guarantee that rate reduction for a period of five years – this will keep distribution rates lower for Orillians on the 20% portion of the bill that is within the power of distribution companies to control.
The cost of electricity (that is delivered through the wires by the distribution system) is not determined locally, and is based on market costs at the provincial level. This is the case now, and will be the case after Orillia transfers its distribution system to Hydro One. For more on how electricity rates are set in Ontario visit www.ontarioenergyboard.ca.

*...Continued on back of this page.*

30244-I-0080

*...Continued from front of this page.*

**When will I become a Hydro One customer?**
The sale must receive final approval from the Ontario Energy Board. The current estimate is that it may take as long as one year for this transaction to close. Upon receiving approval, a transition plan will be put in place and it will take several more months for the transition to be implemented. All customers will receive advanced notification as to the timing for moving from Orillia Power bills to Hydro One bills. Presently, there is no change to any of the services Orillia Power provides – billing, customer service, new services, outage response, etc.

> "The Orillia District Construction Association is supportive of any significant project which will positively impact the community as a whole. The jobs created through this development will result in new home construction, renovations and spin-off benefits to the local construction industry."
>
> -CRAIG BASARABA, PRESIDENT OF THE ORILLIA DISTRICT CONSTRUCTION ASSOCIATION

## How we met all of our negotiating principles

| Negotiating Principles | Outcomes |
|---|---|
| **Provides real short and long-term economic development benefits for the community through significant investment, including the creation of new, highly-skilled, knowledge-based jobs and potential spin-off benefits.** | • $200 to $300 million investment – one of the largest in the City's history.<br>• Construction of three buildings estimated at more than $150 million.<br>• The construction of the ISOC will require Hydro One to upgrade fibre optics in the area.<br>• Employees at the Hydro One facilities are expected to receive a cumulative $30 million in payroll/incomes that could be inputted into the Orillia economy year over year. |
| **Provides a multi-year window of price stability on the cost of power distribution.** | • Distribution rates will be reduced by 1% and guaranteed for a period of five years (distribution accounts for approximately 20% of the overall electricity bill). |
| **Protects the interests of Orillia Power customers and the Orillia community.** | • Rate reduction as noted above.<br>• Hydro One urban service levels in areas similar to the City of Orillia are comparable to Orillia Power service levels.<br>• Large annual increase to municipal tax assessment, economic development spin-off benefits; new, high-quality job creation. |
| **Sees Hydro One working with the City to protect Orillia Power Distribution Corporation (OPDC) jobs.** | • All OPDC employees are moving to Hydro One at similar compensation, benefits, life insurance etc., provided by Hydro One. |
| **The City of Orillia will retain ownership of Orillia Power Generation Corporation (OPGC), including the annual dividend.** | • City retains complete ownership of OPGC, along with annual dividend to the City. |
| **Recognizes the full value of the Orillia Power distribution system – and that value will be independently valued by a qualified, third party.** | • $26.35 million purchase price for the shares of OPDC; this is more than twice their current book value - validated by an accredited third party. |
| **Sustains the level of philanthropic support provided by OPDC to the community.** | • Hydro One will continue to participate in community events and economic development in the City of Orillia with its own programs. |
| **Provides significant value and ongoing financial returns for the City.** | • Approximately $36 million will be deposited into a Legacy Fund and generate investment income for years to come.<br>• Hydro One will contribute $250,000 towards a community project to be jointly selected with the City. |

**For more information visit orillia.ca/techhub or contact the Mayor's Office at 705-325-2447.**

**Join us for one of two public meetings on Thursday, September 29, 2016, at the Orillia City Centre, 50 Andrew St. S., 2-4 p.m. or 7-9 p.m.**

ORILLIA
INCORPORATED 1867

# Community Investment with Hydro One

Read this flyer to learn more about:

- ECONOMIC DEVELOPMENT BENEFITS
- NEW JOBS COMING TO ORILLIA
- LOWER DISTRIBUTION DELIVERY RATES
- HOW THIS BENEFITS YOU!

## TWO PUBLIC INFORMATION SESSIONS

(For City of Orillia residents and business owners)

**Thursday, September 29, 2016**

**Orillia City Centre, Council Chamber**

**50 Andrew St. S.**

**2 - 4 p.m. or 7 - 9 p.m.**

*Control room at the Ontario Grid Control Centre.*

**Visit orillia.ca/techhub for more information or contact the Mayor's Office at 705-325-2447.**

# How we got to where we are today

- September 2015 – Orillia Council announced it was entering into negotiations with Hydro One on an opportunity that would have Hydro One locating an Advanced Technology Hub in West Orillia and purchasing the Orillia Power Distribution Corporation.
- Council endorsed negotiations based on a set of principles.
- Council held two formal public consultations (January 2016 and June 2016) to enable the public to ask questions and provide comments.
- Mayor Clarke spoke to dozens of community groups about the opportunity and numerous ward meetings were held throughout the year with this topic being discussed.
- Council Members were updated in detail about the transaction throughout the negotiations.
- Orillia Power Corporation Board of Directors voted in favour of the deal on Aug. 12, 2016.
- Council voted in favour of the deal and agreements were signed by the City of Orillia, Orillia Power Corporation and Hydro One on Aug. 15, 2016.

"Lakehead University looks forward to working with Hydro One as it establishes a presence in the City of Orillia, and we are particularly excited about its plans to build an Advanced Technology Hub across from the Orillia Campus.

We look forward to exploring how our two institutions might establish **mutually beneficial collaborations**; for example, potential research projects, teaching opportunities for Hydro One employees, co-op and field placement opportunities for our students, and much more.

Of special note, **Lakehead will begin offering an undergraduate electrical engineering program**, in concert with our partner Georgian College in the fall of 2017, and we hope that the establishment of this program will afford a host of other opportunities for future collaboration between Lakehead and Hydro One."

-KIM FEDDERSON, PRINCIPLE OF LAKEHEAD UNIVERSITY'S ORILLIA CAMPUS

"As a business owner in the City of Orillia I couldn't be more pleased with Council on brokering the Hydro One deal. Orillia will **feel the economic spin-offs for years to come** through the creation of new, high-quality jobs and improved technology infrastructure in Orillia. Orillians should be proud that our City was solicited by Hydro One for these new facilities. More so, we should be proud of our Council and Mayor for being progressive and truly keeping in mind what is best for our City. Bravo Orillia."

-GREG MORTON, PRESIDENT OF MORTON METALS


*Mayo Schmidt, President & CEO of Hydro One Limited, and City of Orillia Mayor Steve Clarke shake hands in front of the City of Orillia Coat of Arms following the signing of agreements on Aug. 15, 2016.*

# How we met all of our negotiating principles

| Negotiating Principles | Outcomes |
|---|---|
| **Provides real short and long-term economic development benefits for the community through significant investment, including the creation of new, highly-skilled, knowledge-based jobs and potential spin-off benefits.** | • $200 to $300 million investment – one of the largest in the City's history.<br>• Construction of three buildings estimated at more than $150 million.<br>• The construction of the Back-up Ontario Grid Control Centre/Integrated Systems Operation Centre (ISOC) will require Hydro One to upgrade fibre optics in the area.<br>• Employees at the Hydro One facilities are expected to receive a cumulative $30 million in payroll/incomes that will be injected into the Orillia economy year after year. |
| **Provides a multi-year window of price stability on the cost of power distribution.** | • Distribution delivery rates will be reduced by 1% and guaranteed for a period of five years (distribution accounts for approximately 20% of the overall electricity bill). |
| **Protects the interests of Orillia Power customers and the Orillia community.** | • Rate reduction as noted above.<br>• Hydro One urban service levels in areas similar to the City of Orillia are comparable to Orillia Power service levels.<br>• Large annual increase to municipal tax assessment, economic development spin-off benefits; new, high-quality job creation. |
| **Sees Hydro One working with the City to protect Orillia Power Distribution Corporation (OPDC) jobs.** | • All OPDC employees are moving to Hydro One at similar compensation, benefits, life insurance etc., provided by Hydro One. |
| **The City of Orillia will retain ownership of Orillia Power Generation Corporation (OPGC), including the annual dividend.** | • City retains complete ownership of Orillia Power Generation along with annual dividend to the City.<br>• OPGC employees will not be transferred to Hydro One. |
| **Recognizes the full value of the Orillia Power distribution system – and that value will be independently valued by a qualified third party.** | • $26.35 million purchase price for the shares of Orillia Power Distribution; this is more than twice their current book value - validated by an accredited third party. |
| **Sustains the level of philanthropic support provided by OPDC to the community.** | • Hydro One will continue to participate in community events and economic development in the City of Orillia with its own programs. |
| **Provides significant value and ongoing financial returns for the City.** | • Approximately $36 million will be deposited into a Legacy Fund and generate investment income for years to come.<br>• Hydro One will contribute $250,000 towards a community project to be jointly selected with the City. |

**Visit orillia.ca/techhub for more information or contact the Mayor's Office at 705-325-2447.**

# How does this deal benefit you?

- **Increased municipal tax assessment** contributed by Hydro One through annual taxes paid to the City helps relieve the overall tax burden on residents.
- **Lower distribution delivery rates for five years** (accounts for approximately 20% of your overall bill). After five years, distribution delivery rates can only rise at a gradual level as approved by the OEB.
- **Strengthens the local economy**, bringing more jobs to Orillia and creating spin-off benefits that improve the overall quality of life in Orillia.
- Approximately **$36 million deposited into a Legacy Fund** will generate investment income for years to come, which will help pay for necessary improvements throughout the City.
- **Upgrade to fibre optics** in the Orillia area should open up opportunities to attract other businesses and suppliers to the area.

ORILLIA INCORPORATED 1867

"The Hydro One investment will contribute to Quality of Life in Orillia through the **creation of local jobs and an increased tax base**. It will attract skilled labour, and offer growth for those members of the Orillia workforce seeking a foothold in a vibrant energy sector that will thrive in the community."

- MIKE TAYLOR, PRESIDENT MUSKOKA HALIBURTON ORILLIA – THE LAKELANDS ASSOCIATION OF REALTORS®

# What does $150 million in construction look like?

Construction cost of the three Hydro One buildings within the Horne Business Park is estimated at more than $150 million. To put that in perspective, the City's six largest construction projects in recent history equal less than that.

ORILLIA INCORPORATED 1867

**Rotary Place** $26 million

**Library** $23 million

**Fire Station 1** $9 million

**Waste Diversion Site** $1.2 million

**Port of Orillia** $2.3 million

**Recreation Facility** $52.8 million

= **$114.3 million**

hydro one
Partners in Powerful Communities

**Back-up Ontario Grid Control Centre/ ISOC**

**Provincial Warehouse**

**Regional Operations Centre**

= **$150 million**

# Frequently Asked Questions (more FAQs available at orilliа.ca/techhub)

**What is Hydro One planning to build within the Horne Business Park?**

Hydro One intends, subject to Ontario Energy Board (OEB) approval, to build three facilities within the Horne Business Park in West Orillia.

- Back-up Ontario Grid Control Centre/Integrated Systems Operation Centre (ISOC) on 16.41 acres of land.
- Provincial Warehouse on 10 acres of land.
- Regional Operations Centre on 10 acres of land.

Hydro One has purchased 16.41 acres of the land required to build the ISOC portion of the development for approximately $3 million – validated as fair market value by a third-party valuator. Construction of the buildings is estimated at more than $150 million. The construction of the ISOC will require an upgrade to fibre optics in the area.

**What are the economic benefits of this deal to the City of Orillia?**

Hydro One plans to build three facilities in Orillia as detailed above. Some of the jobs located in the new facilities will be transferred from the existing Orillia Power Distribution Corporation facilities. Hydro One will also introduce a significant number of entirely new, high-quality, knowledge-based jobs to Orillia, along with construction/trades jobs for the development.

In the short term, the economic impact of the construction of the buildings and related activity is anticipated to inject $200 to $300 million into the Orillia economy. Once all the facilities are operational, employees at this Orillia facility are expected to receive a cumulative $30 million in payroll/incomes that will be injected into the Orillia economy year after year. This will result in economic spin-offs through the creation of new jobs and additional spending in housing construction, retail, restaurants, personal services (i.e. dentists, taxis), schools and colleges, and many other fields throughout the Orillia economy.

Additionally, this technology investment by Hydro One will likely create improved infrastructure for other businesses, open up opportunities to entice investment in related businesses and suppliers, and send a signal to other corporate entities that Orillia is a great place to build a technology platform.

"The Orillia District Construction Association is supportive of any significant project which will **positively impact the community as a whole**. The jobs created through this development will result in new home construction, renovations and spin-off benefits to the local construction industry."

-CRAIG BASARABA, PRESIDENT OF THE ORILLIA DISTRICT CONSTRUCTION ASSOCIATION

**What happens to Orillia Power Generation Corporation?**

This deal has no impact on the employment of Orillia Power Generation Corporation employees. The generation side of Orillia Power is still owned by the City of Orillia along with the annual dividend, which accounts for the majority of the overall Orillia Power dividend received by the City. Orillia Power generation jobs are not impacted. Once the OEB has approved the sale of OPDC, the generation company will relocate to a different facility in Orillia.

**What will happen to service levels once I become a Hydro One customer?**

Ultimately, the service activity would remain the same within Orillia's boundaries should Hydro One acquire the distribution side of Orillia Power. At the public information session on Jan. 12, 2016, Hydro One representatives made it very clear that the people serving Orillia today from Orillia Power will likely be the same people serving you should a deal go through. That is certainly the case now that we know that all Orillia Power Distribution employees are guaranteed employment and a one-year location guarantee with Hydro One.

As for service levels, Orillia is often compared to surrounding townships serviced by Hydro One. It is important to understand the distinction and challenges between servicing rural areas, such as the townships, versus urban areas, such as the City of Orillia. Rural areas experience much more inclement and extreme weather compared to urban centres, which impacts the distribution system and its ability to be restored promptly during and after a storm event. There are many hundreds of miles of wires and poles scattered over large distances in the surrounding townships. It takes Orillia Power workers 11 minutes to get from one end of Orillia to the other, with switches required to restore power located extremely close together. Orillia has the ability for a quick recovery; rural settings do not.

**What happens to existing Orillia Power Distribution Corporation employees?**

All OPDC employees will be transferred to Hydro One and will receive a one-year location guarantee. Compensation, pensions, benefits, life insurance etc. for these employees will continue with similar terms provided by Hydro One. Until the Regional Operations Centre is constructed, Hydro One will be situated in the existing OPDC building on West Street.

## How will this deal affect my electricity rates?

It is important to acknowledge that the infrastructure of Orillia Power will need upgrading over the next decade – a cost that would likely have driven Orillia Power distribution rates up by almost 10% over the next number of years. Upon closing, which requires Ontario Energy Board approval, Hydro One will lower distribution delivery rates by 1% and guarantee that rate reduction for a period of five years – this will keep distribution rates lower for Orillians on the 20% portion of the bill that is within the power of distribution companies to control.

The cost of electricity (that is delivered through the wires by the distribution system) is not determined locally, and is based on market costs at the provincial level. This is the case now, and will be the case after Orillia transfers its distribution system to Hydro One. For more on how electricity rates are set in Ontario visit www.ontarioenergyboard.ca.

*...FAQs continued on next page*

...FAQs continued from previous page

**How much is the City making from the sale of the distribution assets of Orillia Power?**
The total value of the deal is approximately $36 million. Hydro One will pay the City of Orillia $26.35 million cash for the shares of OPDC; this is more than twice their current book value. The City also holds $9.7 million in OPDC debt, which will be returned to the City at the close of the transaction.

**What is the City of Orillia doing with proceeds from the sale?**
All proceeds from the sale (approximately $36 million) will be invested into a (perpetual) Legacy Fund with the One Investment Program. The Legacy Fund will be a segregated fund containing investments in the common shares of companies having a long history of paying dividends. On an annual basis, the City would draw 95% of the income earned on the fund. This leaves the initial proceeds of the sale, plus 5% of each subsequent year's income, as the principal amount in the fund. Because the principal will be growing each year, it is expected that the income earned on the principal will grow each year. The annual return on this investment will likely be greater than the OPDC portion of the annual dividend provided by Orillia Power. Investing the proceeds into the Legacy Fund removes the temptation of future Councils to simply spend the principal amount on a current or future project.

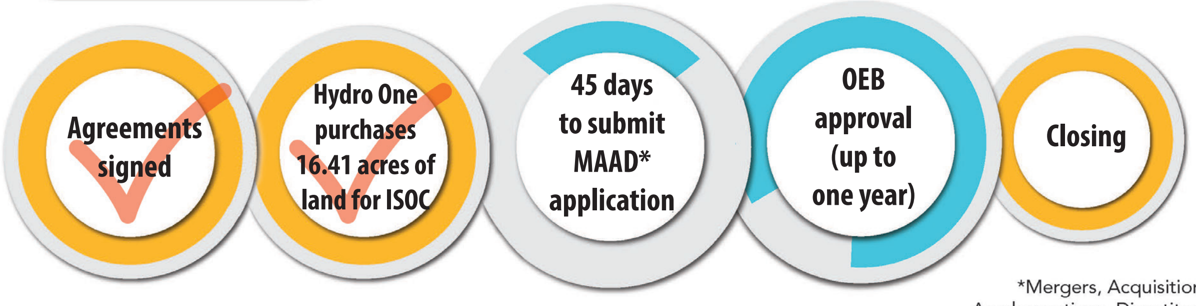
> "As a business owner committed to the long-term well-being of our community, I am thrilled to see a corporate investment of this magnitude being made in Orillia, which will in turn **make our entire community more prosperous."**
>
> - JIM WILSON, OWNER OF JIM WILSON CHEVROLET BUICK GMC

**Are there guarantees that ensure Hydro One will follow through on their plans?**
The electricity industry is a highly-regulated industry and the acquisition of OPDC and the construction of the Back-up Ontario Grid Control Centre/Integrated System Operations Centre (ISOC) are contingent on OEB approval. Hydro One does not have the authority to speak on behalf of or bind the OEB to a decision; therefore, there is no guarantee contained within the signed agreements. However, Hydro One officials have expressed confidence they will proceed with the development plans because there is a documented need for these facilities in Ontario. Hydro One has also demonstrated their commitment by purchasing 16.41 acres of land within the Horne Business Park for approximately $3 million to accommodate the ISOC building pending OEB approval.
Upon OEB approval of the sale of OPDC to Hydro One, and as soon as suitable sites are available in the Horne Business Park, Hydro One will move forward with the Provincial Warehouse and the Regional Operations Centre developments.

## UPDATE: Hydro One submits Site Plan Approval application for ISOC

All Agreements with respect to the Hydro One matter were executed by the City of Orillia, Orillia Power and Hydro One on Aug. 15, 2016. City staff continue to work with Hydro One in order to ensure that all of the proposed facilities will be located within Orillia in accordance with the agreements that have been executed. City staff have met with Hydro One's consulting team that is working on the ISOC facility, and a formal (required) pre-consultation meeting has taken place. A Site Plan Approval application for the ISOC facility was submitted on Sept. 13. It is anticipated that all of the Hydro One facilities will be constructed within five years of receiving OEB approval.

## What's next:




*Mergers, Acquisitions, Amalgamations, Divestitures

> "The scale of the unique investment that Hydro One intends to make in Orillia opens up the door to **significant economic development** opportunities for our community and had to be pursued. Orillia Council has evaluated this deal thoroughly and is represented by the best energy lawyer in all of Ontario to ensure **Orillia's interests are well protected**. I look forward to the economic spin-off benefits this deal will bring to the Orillia area."
>
> - DOUG DOWNEY, DOWNEY TORNOSKY LASSALINE & TIMPANO LAW

# MORE BIG NEWS FOR THE CITY OF ORILLIA

## Costco is coming to Orillia

- Construction has started on Costco's 156,000-sq.ft retail warehouse, gas bar, propane station and seasonal garden centre.
- Located on University Avenue across from Diana Drive.
- Will employ approximately 250 full and part-time workers.
- The opening of Costco will help solidify Orillia as a regional retail hub in the area, drawing shoppers from across the greater region including Muskoka to the north, Lindsay to the east, and Midland to the west.
- Opening date to be determined.


## City Council awards recreation tender to The Atlas Corporation

- Council awarded the construction of the Orillia Recreation Facility at 255 West St. S. to The Atlas Corporation for $48,450,000.
- The Orillia Recreation Facility project includes an aquatic centre (lap pool, leisure pool, and therapy pool), gymnasiums, multi-purpose rooms, a walking/jogging track, Orillia Sport Hall of Fame, preschool room, office space and a fitness centre.
- Contractor is on site and site preparation is underway.
- Scheduled to open in 2018.

## Orillia announced as host of the 2018 Ontario Winter Games

- The Ministry of Tourism, Culture and Sport announced the City of Orillia as the host of the 2018 Ontario Winter Games.
- The Games will attract more than 3,000 athletes, competing in approximately 25 sports over the four-day event.
- The City is partnering with Oro-Medonte, Gravenhurst, Midland, Chippewas of Rama First Nation, Huntsville, Tourism Simcoe County and Ontario's Lake Country.
- The City will receive $1 million in provincial funding through a hosting grant, which includes a $100,000 deficit guarantee and/or legacy fund.


## PROJECTS COMING UP SOON...

- Hwy 12/West Orillia roadworks
- Hwy 11/Old Barrie Road Intersection Improvement
- Orillia Waterfront Centre
- Tertiary Treatment Facility

#ORILLIA150
1867-2017

Visit orillia.ca/majorprojects for more information.

ORILLIA
INCORPORATED 1867

**NEWS RELEASE**

# City of Orillia will review options for consideration for Hydro One

**For immediate release (April 12, 2018)** – The City of Orillia has received notification that in a decision dated April 12, 2018, the Ontario Energy Board (OEB) has denied the application for the sale of Orillia Power Distribution Corporation to Hydro One Inc. (Hydro One).

The City of Orillia will be reviewing the decision and supporting documentation provided by the OEB and exploring what options are available moving forward. Staff will be reporting to Council with further information as soon as they are able.

The negotiations between the City of Orillia and Hydro One formally started in September 2015. Mayor and Council members undertook two formal public consultations and numerous meetings throughout the community to enable the public to provide comments on the opportunity. In August 2016, a final deal was reached between the City of Orillia and Hydro One. Submission to the OEB for approval took place in September 2016.

The City of Orillia is a city of 31,000 people in the heart of Ontario's Lake Country on the shores of Lake Couchiching and Lake Simcoe. Visit our website at **orillia.ca**.

-30-

Melissa Gowanlock
Manager of Communications
705-325-8929
705-238-9209 (cell)
magowanlock@orillia.ca

# ENERGY PROBE INTERROGATORY # 2

**Reference:**
Exhibit A, Tab 1, Schedule 1, Page 8

**Interrogatory:**
**Preamble:** "The implementation of Hydro One's ESM benefits and protects OPDC customers during the extended deferred rebasing period by guaranteeing $3.2 million, established on an estimate of savings from the transaction."

**Question:**
a) What will be the impact on Hydro One ratepayers (excluding OPDC ratepayers) if actual earnings are higher or lower than expected?

b) If the earnings are not adequate to support the $3.2 ESM million credit to ratepayers, how will the credit be financed?

**Response:**
a) Hydro One legacy ratepayers, excluding OPDC ratepayers will not be harmed if actual earnings are higher or lower than expected. Any disparity between actual cost structures and the actual revenues collected during the deferred rebasing period are at the risk of the shareholder.

b) As per part a) above, any OPDC earnings, or levels of savings and synergies that are not adequate to support the $3.2M ESM credit to ratepayers will fall to the account of the shareholder and not be paid for by Hydro One legacy customers.

# ENERGY PROBE INTERROGATORY # 3

**Reference:**

Exhibit A, Tab 2, Schedule 1, Page 2, Table 1; Exhibit A, Tab 2, Schedule 1, Page 23

**Interrogatory:**

**Question:**

a) Please provide the supporting calculations for each OM&A and Capital number shown in Table 1.

b) Are the numbers shown in Table 1 based on USGAAP or MIFRS? Please explain your answer.

c) As USGAAP allows for capitalization of certain costs that are treated as OM&A by MIFRS please provide the amounts for each year that will be transferred from OM&A to Capital as the result of adoption of USGAAP after the merger.

**Response:**

a) Refer to Exhibit 1, Tab 1, Schedule 19 part a)

b) The Status Quo scenario is based on MIFRS, the accounting standard which OPDC is anticipated to continue to utilize absent a transaction.

The Hydro One Forecast is based on USGAAP, Hydro One's current accounting standard, which Hydro One also intends to utilize while serving the former OPDC territory.

c) Please see response to Exhibit I, Tab 2, Schedule 4.

# ENERGY PROBE INTERROGATORY # 4

**Reference:**
Exhibit A, Tab 2, Schedule 1, Page 3

**Interrogatory:**
**Preamble:** "OPDC's current Base Distribution Delivery Rates will be reduced by 1%, for residential and general service customers of OPDC, and frozen for a period of five years from closing of this transaction."

**Question:**

a) Please explain the purpose of the 1% reduction.

b) Please explain how the 1% reduction was determined and show all calculations.

c) Please explain the relationship between the 1% reduction in delivery rates and the $3.2 million ESM credit.

**Response:**

a) The 1% rate reduction is a negotiated component of the commercial transaction between a willing buyer and a willing seller.

b) Please see part a). There are no calculations to determine how the 1% reduction was arrived at.

c) There is no relationship between the 1% reduction in delivery rates and the ESM credit. The 1% reduction applies to base distribution rates in Years 1 to 5 of the deferral period. The ESM calculation takes into consideration over-earnings in Years 6 to 10. Once the initial 5-year deferral period elapses such that base distribution rates will no longer be frozen, nor have the 1% rate rider reduction, OPDC customers' last OEB-approved rates will be adjusted by the Board's Price Cap IR adjustment mechanism in each of years 6 to 10.

# ENERGY PROBE INTERROGATORY # 5

**Reference:**
Exhibit A, Tab 2, Schedule 1, Page 13

**Interrogatory:**
**Preamble:** "In addition, Hydro One will eliminate all 19 indirect positions solely focused on the OPDC territory in the management, back office, and indirect trades and technical areas. "

**Question:**
a) What is the cost that Hydro One will allocate to customers of OPDC for the provision of management, back office, and indirect trades services that were provided by the staff in 19 positions prior to amalgamation?

b) Please explain the cost allocation methodology Hydro One uses for allocating such costs to acquired utilities and explain how it will be applied to OPDC during the 10 year period after amalgamation and following the 10 year period. If the allocation methodology is different for OPDC than for other acquired utilities please explain why that is the case.

**Response:**
a) The cost of management, back office, and indirect trades services will be allocated to OPDC customers as discussed in part b). It is not possible to identify the costs that will be allocated to OPDC customers specifically associated with the services previously provided by the staff in the 19 positions referenced.

b) During the 10 year deferral period Hydro One will be tracking the incremental cost to serve OPDC customers. There will be no cost allocation methodology during that time as OPDC customers' rates will be set as described in the Application.

After the 10 year deferral period Hydro One proposes to allocate Hydro One's total revenue requirement, which will include the Residual Cost associated with serving OPDC customers, to all Hydro One legacy and OPDC acquired classes using the principles embedded in the OEB's cost allocation model. To appropriately allocate costs to the OPDC rate classes, Hydro One will use adjustment factors (as described in Exhibit I, Tab 1, Schedule 9) to effectively directly allocate the amount of local fixed assets (USofA 1815 to 1860) used in serving the OPDC rate classes. The accurate allocation of fixed assets is key to ensuring that an appropriate share of Hydro One's total costs are allocated to the OPDC classes using the principles embedded in the OEB's cost allocation model.

Shared costs, which would include the types of costs referenced in the question, will be allocated to all rate classes, including both legacy and OPDC rate classes, on the same basis using the principles and allocators embedded within the OEB's cost allocation model for the allocation of such costs.

# ENERGY PROBE INTERROGATORY # 6

**Reference:**
Exhibit A, Tab 2, Schedule 1, Page 20

**Interrogatory:**
**Question:**

a) What is the latest estimate of the transaction and integration costs for Hydro One and for OPDC?

b) How much has been spent to date on transaction and integration costs by Hydro One and OPDC and which accounts are being used by Hydro One and OPDC to record these costs?

c) The evidence claims that all incremental costs will be financed through productivity gains. How will Hydro One keep track of actual productivity gains during the 10 year period to ensure that they are adequate to cover the incremental costs?

**Response:**

a) The following table provides a breakdown of incremental transaction and integration costs.

**Table 1**

| Hydro One Forecast - $M<br>Incremental Transaction and Integration Costs | Closing | Year 1 | Year 2 |
|---|---|---|---|
| Part III.1 Tax on Excessive Eligible Dividend Designations | 2.5 | | |
| Legal Fees / Regulatory Approval / Land Transfer Tax | 0.4 | | |
| **Total Transaction Costs** | **2.9** | | |
| **Total Integration** (Customers, Assets, Employees) | | **6.0** | **0.2** |

In addition to the costs noted above, Hydro One expended significant effort developing the transaction proposal, negotiating definitive transaction agreements and seeking EB-2016-0276 regulatory approval. These activities represent costs which have occurred prior to the EB-2018-0270 regulatory approval process and will not be funded by ratepayers.

The shareholder of OPDC and the City of Orillia are both responsible for funding their own transaction costs. Under no scenario will the customers of OPDC bear these transition costs.

b) See part a) above.

As of April 30, 2019, Hydro One Inc.'s transaction and integration costs are $0.2 million. These expenses will not be funded by ratepayers.

c) All incremental transaction and integration costs will be paid for by the Hydro One's shareholder and will be financed through efficiencies gained in the deferral period by charging OPDC customers their current-approved rates. This is consistent with the Board's *Rate-Making Associated with Distributor Consolidation* 2015 policy that allows the net savings of a consolidation to accrue to a distributor's shareholders for the deferral period. In Exhibit A, Tab 5, Schedule 1, page 2, Hydro One commits to tracking the cost to serve OPDC customers in the deferred rebasing period. Hydro One will also track the incremental transaction and integration costs. However, as the productivity gains will accrue to the shareholder, these will not be specifically tracked.

# ENERGY PROBE INTERROGATORY # 7

**Reference:**
Exhibit A, Tab 3, Schedule 1, Page 4

**Interrogatory:**
**Preamble**: "A significant benefit to OPDC customers is that the OM&A costs used in the model are incremental costs only, which do not include corporate overheads. Including corporate overheads would reduce net income, thereby reducing shared earnings. Hydro One's Year-10 forecast OM&A costs are approximately 70% less compared to OPDC's status quo Year-10OM&A forecast."

**Question:**
Please provide the amount of corporate overheads excluded in the model for each year of the 10 year period.

**Response:**
The development of the Hydro One Forecast focused on capturing all incremental costs to serve the former OPDC territory. Activities deemed non-incremental (including non-incremental corporate overhead activities) were neither captured nor assigned a cost as part of the forecast development.

# ENERGY PROBE INTERROGATORY # 8

**Reference:**
Exhibit A, Tab 3, Schedule 1, Page 6

**Interrogatory:**
**Preamble:** "Hydro One will have a strong incentive to ensure that these savings are achieved so that its ability to recover acquisition costs will not be eroded."

**Question:**

a) Please reconcile this statement with the claim at Exibit A, Tab 2, Schedule 1, Page 20 that all incremental costs will be financed through productivity gains

b) How will Hydro One track actual savings during the 10 year period?

c) What will Hydro One do if the savings are not as great as expected and Hydro One's ability to recover acquisition costs is eroded?

**Response:**

a) The OEB's MAADs policies allow consolidating entities up to a 10-year period to recover the acquisition costs associated with the consolidation. In Exhibit A, Tab 2, Schedule 1, Hydro One provides evidence that it will not be seeking recovery in rates of the incremental transaction and integration costs as discussed on page 20. Since they are not being recovered in rates they will either be recovered through productivity gains earned during the deferral period or will be paid out of shareholder earnings.

   In Exhibit A, Tab 3, Schedule 1, Hydro One is referencing its guaranteed ESM. Hydro One will be incented to ensure that the level of savings forecast in its ESM model are achieved in order to not erode its ability to recover acquisition costs. If Hydro One is able to meet or surpass the savings used in calculating the ESM, it will not only benefit Hydro One over the 5-year ESM period, but it will result in higher efficiencies to operate the assets of OPDC, these efficiencies would be expected to be ongoing.

b) During the ten year rebasing deferral period Hydro One will utilize its financial management and reporting system, the same system it uses for all Hydro One's financial business activities, to track incremental capital and OM&A costs to serve OPDC's customers. Hydro One's financial system will enable the reporting of these capital and OM&A expenditures over this ten year period by setting up a specific OPDC service territory cost centre. Any specific incremental cost expenditures made in OPDC's service territory during that period will be recorded and tracked in that OPDC cost centre.

c) If Hydro One is unable to attain the synergy savings as forecast, OPDC customers will still be entitled to the guaranteed ESM and Hydro One's shareholder will incur the loss.

# ENERGY PROBE INTERROGATORY # 9

**Reference:**
Exhibit A, Tab 4, Schedule 1, Page 4, Table 2

**Interrogatory:**
**Question:**
Please provide the calculation that supports the estimate of the $1,005 thousand LV charges for Year 11.

**Response:**
To estimate the LV charges for Year 11 (2030), average rate increases of 6.3%[1] for Cost of Service years and 1.55%[2] for IRM years were applied to OPDC's LV charges paid to Hydro One in 2017[3]. Table below provides the detailed calculations.

| Year | Annual Change | | LV Revenue ($M) |
|---|---|---|---|
| **2017** | - | - | $0.7 |
| **2018** | **COS** | 6.30% | $0.8 |
| **2019** | **IRM** | 1.55% | $0.8 |
| **2020** | **IRM** | 1.55% | $0.8 |
| **2021** | **IRM** | 1.55% | $0.8 |
| **2022** | **IRM** | 1.55% | $0.8 |
| **2023** | **COS** | 6.30% | $0.9 |
| **2024** | **IRM** | 1.55% | $0.9 |
| **2025** | **IRM** | 1.55% | $0.9 |
| **2026** | **IRM** | 1.55% | $0.9 |
| **2027** | **IRM** | 1.55% | $0.9 |
| **2028** | **COS** | 6.30% | $1.0 |
| **2029** | **IRM** | 1.55% | $1.0 |
| **2030** | **IRM** | 1.55% | $1.0 |

[1] See EB-2017-0320, Hydro One Reply Submission December 13, 2017 – Attachment 1
[2] 1.55% was calculated based on: Inflation of 2.0% minus Hydro One productivity & stretch factor of 0.45%.
[3] Hydro One's distribution rates application cycle was followed since OPDC's LV charges are dependent on Hydro One's Sub-Transmission rates.

# ENERGY PROBE INTERROGATORY # 10

**Reference:**

Exhibit A, Tab 4 Schedule 1, Page 6

**Interrogatory:**

**Preamble:** "The $6.9 M Residual revenue requirement does not reflect OPDC customers paying their full share of the costs for services that Hydro One would be providing to OPDC customers."

**Question:**

a) What would be Residual Revenue Requirement in Year 11 if OPDC customers were paying their full share of costs of services that Hydro One would be providing to OPDC?

b) Please confirm that if party A to a shared services agreement does not pay their full share of costs than party B is paying an amount that is greater than its full share which means that party B is subsidizing party A.

**Response:**

a) The term "Residual Revenue Requirement" as used in this application refers to the incremental amount of revenue requirement that would be added to Hydro One's Total Revenue Requirement associated with serving OPDC customers. The Residual Revenue Requirement is independent of any allocation of costs. The question appears to be looking for the total costs that would be allocated to OPDC customers in Year 11, which would include all costs (including shared costs) associated with providing service to OPDC customers. The total allocated costs associated with serving OPDC customers is $10.2M, as determined in the response to Exhibit I, Tab 1, Schedule 9 part b).

b) The question is not relevant as Hydro One and OPDC are not parties to a shared services agreement. However, with respect to the treatment of shared costs, as explained in Exhibit A, Tab 5, Schedule 1, section 5.0 "Sharing of Consolidation Savings", all ratepayers of Hydro One will benefit as a result of this transaction. Any allocation of Hydro One's shared costs to OPDC will result in a reduction to

Legacy customer's revenue requirement. Legacy customers **will not** be paying any shared costs greater than the amount that they would currently be paying in the absence of the acquisition of OPDC.

# ENERGY PROBE INTERROGATORY # 11

**Reference:**
Exhibit A, Tab 4, Schedule 1, Pages 4 and 5, Table 3

**Interrogatory:**
**Preamble:** Tax expense shown in Table 3 in the evidence filed 2018-09-26 was $687 thousand and in the evidence filed on 2019-04-26 is $227 thousand.

Please provide a detailed reconciliation that explains the change in the tax expense.

**Response:**
Hydro One updated the tax expense found in Table 3 of Exhibit A, Tab 4, Schedule 1 to correct an error in the classification of assets into the correct UCC rate pool and to correct an error in the excel model, which was linking to the "total" tax line, whereas the ESM model should have picked up only the "current" tax line.

A reconciliation of items impacting the change in the tax values are as follows;

| Tax Item in the Year-11 Residual Cost to Serve Scenario | Value ($000's) |
|---|---|
| Original Tax Value | $687 |
| | |
| <less> Tax type category error | (361) |
| <less> UCC Pool updated impact | (99) |
| | |
| Updated Tax Value | **$227** |

Hydro One confirms no other underlying assumptions other than those listed above were used in the computation of the Year-11 Residual Cost to Serve Revenue Requirement, as presented in the evidence, have changed.

# ENERGY PROBE INTERROGATORY # 12

**Reference:**

Exhibit A, Tab 4, Schedule 1, Page 8, Table 4

**Interrogatory:**

**Question:**

a) Please confirm that according to Hydro One is the net benefit of the merger is $6.584 million, the difference between the $14.448 million Total Cost to Serve - OPDC Status Quo and the $7.864 million Total Residual Cost to Serve. If the answer is no, please give explain your answer.

b) Is the $6.584 million difference composed of three components: the less than full share of shared services costs, the difference in capitalization between USGAAP and MIFRS, and assumed savings from staff reductions? If the answer is yes, please provide the amount of each component in Year 11. If the answer is no please provide the reasons for your answer and the list of Hydro One's components that total $6.584 million, giving the amount of each component.

**Response:**

a) The $6.6M represents the annual expected savings to OPDC's underlying cost structures, when compared to the status quo. These are sustainable benefits expected to accrue to all ratepayers and would not occur, absent the transaction. These benefits can be classified as quantifiable benefits. Other benefits that are not as easily quantifiable in dollar value terms, which should also be considered when accounting for all the transaction benefits that will impact OPDC customers are those detailed in Exhibit A, Tab 4, Schedule 1, on pages 17 to 19. These consist of positive customer service additions, such as; increased call centre hours, enhanced outage notification and access to information, and initiatives to help customers manage there bill, including new services such as Hydro One's web-portal and MyAccount access for billing related information and assistance.

b) No. The $6.6M savings has been explained throughout the evidence and represents costs that will be removed from the combined revenue requirements of Hydro One and OPDC if this consolidation transaction is approved. This means that Hydro

One's (including OPDC) ratepayers will no longer be incurring $6.6M in costs. A comparison of the differences in the Year 11 (2030) underlying cost structures, on a revenue requirement component basis is provided at Attachment 18 to the prefiled evidence, with all assumptions for both the Status Quo and Residual Cost to Service scenarios being provided at Attachment 20 to the prefiled evidence.

# ENERGY PROBE INTERROGATORY # 13

**Reference:**
Exhibit A, Tab 5, Schedule 1, Page 1

**Interrogatory:**
Please explain the mechanism that Hydro One will use to track capital costs and incremental OM&A costs to serve OPDC customers after the rebasing period. Please provide a numerical example with illustrative numbers.

**Response:**
For clarification, Hydro One has only committed to tracking capital costs for the former OPDC service territory after the rebasing period, as per Exhibit A, Tab 5, Schedule 1, pages 2 and 3. As described in that exhibit, the cost allocation model used to determine rates for customer classes uses fixed assets as the primary allocator to distribute OM&A costs amongst rate classes. Therefore, the tracking of OM&A beyond the deferral period is not required.

Hydro One will utilize its financial management and reporting system, the same system it uses for all Hydro One's financial business activities, to track OPDC's capital costs. Hydro One's financial system will enable the reporting of future OPDC capital costs in perpetuity by setting up a specific OPDC service territory cost centre. Any specific capital cost expenditures made in service territory going forward will be recorded and tracked in the OPDC Cost Centre.

A numerical example of how Hydro One tracks cost is provided below.

| **$000s** | **QX 20XX Actual** |
|---|---|
| **Capital Costs** | |
| Number of Labour Hours | 48 |
| Labour Rate | $77 |
| **Labour Cost Total** | **$3,707** |
| Fleet costs | $1,059 |
| **Total Cost** | **$4,766** |

# ENERGY PROBE INTERROGATORY # 14

**Reference:**

Exhibit A, Tab 5, Schedule 1, Pages 6 and 7

**Interrogatory:**

Please provide more information on Hydro One's proposed adjustment factors by providing the following information.

a) Please list the proposed adjustment factors.

b) Please explain how each adjustment factor will be calculated.

c) Please provide a numerical example of each adjustment factor.

**Response:**

a) to c) Please see the response to Exhibit I, Tab 1, Schedule 9, part a).

# ENERGY PROBE INTERROGATORY # 15

**Reference:**
Exhibit A, Tab 5, Schedule 1, Page 9

**Interrogatory:**

a) Why did Hydro One find it necessary to engage Navigant Consulting to evaluate its cost allocation approach?

b) Did Hydro One issue an RFP for this work? If the answer is yes, please provide the RFP. If the answer is no, please explain why not.

c) Please file the statement of work or any similar document that Hydro One used to communicate to Navigant the consulting assignment.

**Response:**

a) Hydro One in its Distribution Rates Proceeding set out its cost allocation and rate design approach for the previously Acquired Utilities. Hydro One had concerns as to the Board's understanding and interpretation of this approach and as such, Hydro One sought an independent expert review of the cost allocation and rate design evidence based on industry experience. Please see Exhibit I, Tab 2, Schedules 34 and 36.

b) No, Hydro One did not issue an RFP for this work. Navigant Consulting is a noted expert in the area of cost allocation and rate design. Hydro One and OPDC wished to file the supplement evidence as soon as possible. To go through an RFP process would have added considerable time and delay to the applications.

c) Please see below.

3. **Scope of Services and Work Product**

The Consultant will:

(a) evaluate whether the cost allocation and rate design approaches described in the Supplemental Evidence are appropriate and consistent with accepted regulatory practices, including, with respect to rate design in particular, whether the adjustment of the revenue-to-cost ratio as described in the Supplemental Evidence is appropriate and consistent with accepted regulatory practices (the "Study");

(b) if requested by Counsel, produce a report detailing the Study's methodology, analysis performed and the Consultant's findings and recommendations (the "Report"), which may be filed with the Board in the applicable Proceeding; and

(c) if requested by Counsel, provide support during the hearing of the applicable Proceeding and testify before the Board in that Proceeding, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Study and the Report, the "Services").

# ENERGY PROBE INTERROGATORY # 16

**Reference:**
Exhibit A, Appendix A, Navigant Report, Page 1

**Interrogatory:**
Are the documents listed on Page 1 a complete list of all documents that were provided to Navigant by Hydro One? If the answer is no, please list the documents that were provided by Hydro One to Navigant but are not listed on Page 1.

**Response:**
Hydro One provided Navigant the following list of documents that were not explicitly identified on Page 1 of Navigant's Report.

From its Distribution Rates Application (EB-2017-0049):

- G1-02-01: Pre-filed evidence that includes discussion/rationale for new acquired rate classes
- G1-03-01: Pre-filed evidence that discusses cost allocation, including for new acquired classes (use of adjustment factors)
- Q-01-01: Updated evidence filed in Dec. 2017 that discusses (starting at page 15) changes made to the allocation of costs to acquired classes (basically included local distribution stations as part of the fixed asset costs subject to the adjustment factors) and also discusses changes made to R/C ratios in order to align with OEB approved ranges.
- Acquired Fixed Assets Summary XLS: The detailed calculations that derive the adjustment factors used in the cost allocation model
- Rate Design 2021 XLS: Calculation of the rates for all classes in 2021
- I-46-VECC-090: An interrogatory response that in part d) describes what is provided in each of the tabs of the "Acquired Fixed Assets" spreadsheet [Should refer to this when looking at that spreadsheet]
- JT3.26-3: A technical conference response where part c) of the response discusses our approach to changing the adjustment factors over time.

All of these documents are available on the OEB's website.

# ENERGY PROBE INTERROGATORY # 17

**Reference:**
Exhibit A, Appendix A, Navigant Report, Page 6

**Interrogatory:**
a) Please discuss Navigant's experience with adjustment factors in other jurisdictions.

b) Did Hydro One provide Navigant with any adjustment factor alternatives? If the answer is yes, please list and explain the alternatives. If the answer is no, please explain how Navigant was able to reach its conclusions in absence of alternatives

**Response:**
a) Navigant has considerable experience developing and implementing cost allocation methods and models in general, and more specifically for utilities that operate in service territories that span multiple regulatory jurisdictions. Navigant's expert, Benjamin Grunfeld, has filed evidence on matters related to Hydro One's cost allocation and rate design (e.g., in Ontario proceedings EB-2012-0136 and EB-2013-0416). Furthermore, the Navigant team involved in the review Hydro One's proposal and the development of the evidence in this proceeding, consisted of individuals who filed evidence and, in some instances, testified in cases involving PacifiCorp's multi-jurisdictional cost allocation as it related to revenue requirement determinations (e.g., Wyoming docket 20000-405-ER-11, Utah docket 10-035-89, Idaho docket PAC-E-08-07) or power supply cost modelling and adjustment mechanisms (Oregon docket UE 307, Wyoming docket 20000-469-ER-15, Utah docket 15-035-03, Idaho docket PAC-E-14-01), Enbridge's multi-jurisdictional corporate cost allocation methodology (Ontario proceeding EB-2012-0459), Enmax's inter-affiliate cost review as part of the company's distribution tariff application (Alberta proceeding 1609784), Gazifere's corporate shared service cost model (Quebec proceeding R-3924-2015), and Nova Scotia Power's cost-of-service and allocation approaches (Nova Scotia M05473), among others.

Direct assignment of costs to customer groups (e.g. jurisdictions or classes) is a common element of such methods and models. OEB staff recognized and the OEB appeared to accept (in its EB-2017-0049 Decision with Reasons, at p. 161-2) that the adjustment factors are a mechanism to represent a direct assignment of assets and depreciation within the OEB's standard Cost Allocation Model (CAM).

b) No, Hydro One did not provide Navigant with alternatives to the use of adjustment factors. However, Navigant did internally consider alternatives such as:
   - direct assignment of costs associated with specific USofA accounts within a single CAM that covers both the acquired and legacy customer classes; and
   - separate CAMs for both the acquired and legacy customer classes.

   Navigant believes that the level of effort and added complexity associated with these alternatives would be more onerous and the result would not be materially different.

# PWU INTERROGATORY # 1

**Reference:**

Ref 1: Exhibit A, Tab 1, Schedule 1, Page 3 of 11(#b):

b) The Purchaser or its affiliates shall offer all active employees of OPDC continued employment in the City of Orillia for a period of at least one year;

Ref 2: Exhibit A, Tab 2, Schedule 1, Page 13 of 25:

**Table 5: Current OPDC Staff**

| | **Direct** | **Indirect** |
|---|---|---|
| Management | - | 8 |
| Back Office | - | 7 |
| Trades & Technical | 15 | 4 |
| **Total** | **15** | **19** |

The 15 direct OPDC positions, currently focused solely on servicing the OPDC service area, will be eliminated. However, as a result of this transaction, new local Hydro One positions will be required and are anticipated to be sourced from the existing 15 OPDC staff complement. Therefore, the result is a net reduction of 6 local trades and technical positions to serve the same territory. In addition, Hydro One will eliminate all 19 indirect positions solely focused on the OPDC territory in the management, back office, and indirect trades and technical areas. The remaining 25 personnel will be absorbed into vacancies within Hydro One Networks.

**Interrogatory:**

a) The evidence indicates that Table 5 shows the 2017 actual OPDC labour split between staff occupying direct and indirect positions. What is the most recent actual, total number of OPDC staff and labour split?

b) What is the most recent number of unionized OPDC staff?

c) Please confirm if the statement in Ref #1(b)- that all active employees would be offered continued employment- applies to all direct and indirect staff. If not, please explain.

d) Please clarify whether or not the statement: "The remaining 25 personnel will be absorbed into vacancies within Hydro One Networks." is referring to the sum of the 6 direct and the 19 indirect positions that will be eliminated as a result the proposed acquisition.

**Response:**

a) Please see Table 1 for OPDC's staffing numbers as of May 31, 2019.

**Table 1: OPDC Staff as of May 31, 2019**

| | **Direct** | **Indirect** |
|---|---|---|
| Management | - | 7 |
| Back Office | - | 6 |
| Trades & Technical | 14 | 3 |
| **Total** | **14** | **16** |

*Reconciliation of Staff Changes (Table 5 to May 31, 2019):*

+1 Linesperson (direct trades & technical)
-1 conservation manager (indirect management)
-1 Operations Control Room (indirect trades & technical)
-1 Billing/Cash/Collections/Reception (indirect back office)
-1 linesperson (direct trades & technical)
-1 engineering staff (direct trades & technical)

b) OPDC has 23 unionized staff as of May 31, 2019.

c) Confirmed.

d) The remaining 25 personnel is referring to personnel associated with 6 local trades and technical positions (direct) and 19 indirect positions as outlined in Exhibit A, Tab 2, Schedule 1. Currently, the remaining staff totals 21.

# PWU INTERROGATORY # 2

**Reference:**

Ref 1: Updated Exhibit A, Tab 1, Schedule 1, Page 5 of 11:

The proposed Transaction will both benefit and protect ratepayers:

Ratepayers will receive the benefit of: (i) a reduction of 1% in their Base Distribution Delivery Rates in Years 1 to 5; (ii) a rate increase of less than inflation in years 6 to 10 (inflation less productivity stretch factor); and (iii) a further guaranteed ESM amount of $3.2 million. In addition, customers will benefit in the longer term from the lower ongoing cost structures.

**Interrogatory:**

a) Please explain how the proposed ESM mechanism better protects customers of OPDC than the ESM mechanism as set out in the Board's 2015 Report wherein ESM would have been calculated on the basis of ROE over-earnings by Hydro One.

**Response:**

a) Hydro One strongly believes that its proposed ESM better protects customers of OPDC than the ESM set out in the Board's 2015 Report. Hydro One's ESM is **guaranteeing** the customers of OPDC a refund of $3.2 million. The ESM as set out in the Board's 2015 Report contemplates using the *consolidated* entity's audited financial statements. Hydro One has not earned an ROE of more than 300 basis points over the OEB-approved ROE in the last 10 years. Due to the size of OPDC as compared to Hydro One, any savings resulting from this transaction would have limited impact on the overall earnings shown in Hydro One's Financial Statements. Proceeding with the type of ESM that is contemplated in the Board's 2015 Report would eliminate the guaranteed refund Hydro One is proposing and also have a less likely chance of being actualized. In the 2016 Handbook, the OEB commented that the "ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the deferred rebasing period."

# PWU INTERROGATORY # 3

**Reference:**

Ref 1: Updated Exhibit A, Tab 2, Schedule 1, Page 2 of 25:

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A** | | | | | | | | | | |
| Status Quo Forecast | 5.5 | 5.7 | 5.8 | 5.9 | 6.0 | 6.1 | 6.2 | 6.4 | 6.5 | 6.6 |
| Hydro One Forecast | 4.1 | 2.0 | 2.1 | 1.7 | 1.7 | 1.7 | 1.8 | 1.8 | 1.8 | 1.9 |
| Projected Savings | **1.4** | **3.7** | **3.7** | **4.2** | **4.3** | **4.4** | **4.4** | **4.6** | **4.7** | **4.7** |
| **Capital** | | | | | | | | | | |
| Status Quo Forecast | 3.2 | 4.3 | 1.5 | 1.8 | 2.8 | 2.8 | 2.9 | 3.0 | 11.1 | 3.2 |
| Hydro One Forecast | 3.4 | 2.4 | 2.4 | 2.5 | 2.6 | 2.8 | 2.8 | 2.9 | 2.9 | 3.0 |
| Projected Savings | **(0.2)** | **1.9** | **(0.9)** | **(0.7)** | **0.2** | **0.0** | **0.1** | **0.1** | **8.2** | **0.2** |

**Interrogatory:**

a) Please confirm if Year 1 of the deferral period is assumed to be 2020.

b) Please explain why Hydro One capital forecasts for Year 1, 3, 4 are higher than the Status Quo capital forecasts resulting in negative savings for those years.

**Response:**

a) Confirmed.

Year 1 in Exhibit A, Tab 2, Schedule 1 Table 1 represents a 12 month period post-closing of the transaction. This period is assumed to most closely align with calendar year 2020.

b) OPDC's Status Quo capital forecast in this application was prepared by anticipating a specific level of capital spending in Years 1, 2, 3, and 4 of the forecast. By comparison, the Hydro One Forecast portrays a longer term average level of anticipated capital expenditures. If the cumulative level of capital spending over the first four years is compared, the totals for both the Status Quo Forecast and the Hydro One Forecast are similar.

# PWU INTERROGATORY # 4

**Reference:**

Ref 1: Updated Exhibit A, Tab 4, Schedule 1, Page 10 of 13:

As of December 2017, $20.7M capital expenditures have been added to OPDC's rate base since their last rate rebasing in 2010, a period of seven years (2011 to 2017).

**Interrogatory:**

a) What is the capital expenditure added to OPDC's rate base in 2018?

b) Please provide OPDC's 2018 consolidated Financial Statements if available.

**Response:**

a) OPDC added $2.4M of capital expenditures to rate base, per Note 5 – Property, Plant, Equipment and Intangibles of OPDC's 2018 financial statements.

b) OPDC's 2018 audited financial statements are provided at Attachment 1 to this Schedule.

# Orillia Power Distribution Corporation

# FINANCIAL STATEMENTS

# December 31, 2018

Energizing Our Community®

## TABLE OF CONTENTS

Tel: 905-898-1221
Fax: 905-898-0028
Toll-Free: 866-275-8836
www.bdo.ca

BDO Canada LLP
The Gates of York Plaza
17310 Yonge Street, Unit 11
Newmarket ON L3Y 7R9 Canada

# Independent Auditor's Report

To the Shareholder of Orillia Power Distribution Corporation

## Opinion

We have audited the financial statements of Orillia Power Distribution Corporation (the "Company"), which comprise the statement of financial position as at December 31, 2018 and the statements of comprehensive income, changes in equity and cash flows for the year then ended, and notes to the financial statements.

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

## Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

## Other Information

Management is responsible for the other information. The other information comprises:

- The management discussion and analysis.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained the management discussion and analysis prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

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

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

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

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

## Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

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

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

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

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

BDO Canada LLP

Chartered Professional Accountants, Licensed Public Accountants
April 24, 2019
Newmarket, Ontario

## STATEMENT OF FINANCIAL POSITION

As at
(in thousands of Canadian dollars)

| | Notes | **December 31 2018** $ | December 31 2017 $ |
|---|---|---|---|
| **ASSETS** | | | |
| **Current Assets** | | | |
| Cash and cash equivalents | | **19** | 482 |
| Accounts receivable | 7 | **4,833** | 3,664 |
| Unbilled energy and distribution revenue | 7 | **3,511** | 3,597 |
| Inventory | 16 | **552** | 569 |
| Prepaid expenses | | **88** | 118 |
| Due from related parties | 15 | **435** | 646 |
| Total current assets | | **9,438** | 9,076 |
| **Non-current Assets** | | | |
| Property, plant, equipment and intangibles | 5 | **31,386** | 30,291 |
| Deferred taxes | 11 | **2,228** | 2,306 |
| Total non-current assets | | **33,614** | 32,597 |
| **Total assets** | | **43,052** | 41,673 |
| Regulatory deferral account debit balances | 4 | **1,470** | 1,455 |
| **Total assets and regulatory deferral account debit balances** | | **44,522** | 43,128 |

The accompanying notes are an integral part of these financial statements

## STATEMENT OF FINANCIAL POSITION

| As at<br>(in thousands of Canadian dollars) | | **December 31 2018** | December 31 2017 |
|---|---|---|---|
| | **Notes** | **$** | $ |
| **LIABILITIES AND SHAREHOLDER'S EQUITY** | | | |
| **Current Liabilities** | | | |
| Bank indebtedness | 9 | **5,050** | 5,000 |
| Accounts payable and accrued liabilities | 12 | **6,309** | 6,837 |
| Payments in lieu of taxes payable | 11 | **800** | 631 |
| Security deposits | 13 | **915** | 262 |
| Current portion of long term debt | 8 | **-** | 210 |
| Due to related parties | 15 | **36** | 122 |
| Total current liabilities | | **13,110** | 13,062 |
| **Non-current Liabilities** | | | |
| Security deposits | 13 | **824** | 596 |
| Post-retirement benefits | 14 | **578** | 578 |
| Deferred revenue | 6 | **1,949** | 1,830 |
| Long term debt | 8 | **9,762** | 10,077 |
| Total non-current liabilities | | **13,113** | 13,081 |
| **Shareholder's Equity** | | | |
| Share capital | 17 | **8,236** | 8,236 |
| Retained earnings | | **7,122** | 6,425 |
| Accumulated other comprehensive loss | | **(90)** | (90) |
| Total shareholder's equity | | **15,268** | 14,571 |
| **Total liabilities and shareholder's equity** | | **41,491** | 40,714 |
| Regulatory deferral account credit balances | 4 | **3,031** | 2,414 |
| **Total equity, liabilities and regulatory deferral account credit balances** | | **44,522** | 43,128 |

The accompanying notes are an integral part of these financial statements

On Behalf of the Board of Directors:

Director Director

## STATEMENT OF COMPREHENSIVE INCOME

Year ended December 31
(in thousands of Canadian dollars)

| | Notes | 2018<br>$ | 2017<br>$ |
|---|---|---|---|
| **Revenue** | | | |
| Recovered energy purchases | 6 | **36,463** | 36,974 |
| Operating revenue | 6 | **8,909** | 8,748 |
| | | **45,372** | 45,722 |
| **Expenses** | | | |
| Energy purchases | | **36,425** | 36,877 |
| Operating expenses | 18 | **5,061** | 4,870 |
| Depreciation and amortization | 5 | **1,223** | 1,187 |
| (Gain) loss on disposal of property plant and equipment | 5 | **59** | (93) |
| | | **42,768** | 42,841 |
| **Income from operating activities** | | **2,604** | 2,881 |
| Finance income | 19 | **12** | 7 |
| Finance cost | 19 | **(818)** | (808) |
| Income before provision for payments in lieu of taxes and net movement in regulatory | | **1,798** | 2,080 |
| Provision for payments in lieu of taxes | | | |
| Current | 11 | **169** | 59 |
| Deferred | 11 | **78** | 448 |
| | | **247** | 507 |
| Profit for the year before net movement in regulatory deferral account balances | | **1,551** | 1,573 |
| Net movement in regulatory deferral account balances including related deferred taxes | 4 | **(374)** | (356) |
| **Comprehensive income for the year** | | **1,177** | 1,217 |

The accompanying notes are an integral part of these financial statements

## STATEMENT OF CHANGES IN EQUITY

| Year ended December 31 (in thousands of Canadian dollars) | Share Capital | Retained Earnings | Other Comprehensive Income (Loss) | Equity Totals |
|---|---|---|---|---|
| | $ | $ | $ | $ |
| **SUMMARY OF CHANGES IN EQUITY** | | | | |
| Balance at December 31, 2016 | 8,236 | 5,808 | (90) | 13,954 |
| **Changes in equity during 2017** | | | | |
| Total comprehensive income for the year | - | 1,217 | - | 1,217 |
| Dividends paid | - | (600) | - | (600) |
| Balance at December 31, 2017 | **8,236** | **6,425** | **(90)** | **14,571** |
| **Changes in equity during 2018** | | | | |
| Total comprehensive income for the year | **-** | **1,177** | **-** | **1,177** |
| Dividends paid | **-** | **(480)** | **-** | **(480)** |
| **Balance at December 31, 2018** | **8,236** | **7,122** | **(90)** | **15,268** |

The accompanying notes are an integral part of these financial statements

## STATEMENT OF CASH FLOWS

Year ended December 31
(in thousands of Canadian dollars)

| | Notes | 2018<br>$ | 2017<br>$ |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Comprehensive income for the year | | **1,177** | 1,217 |
| Adjustments to reconcile comprehensive income to net cash from (used in) operating activities | | | |
| Depreciation and amortization (non-cash) | 5 | **1,223** | 1,187 |
| Other non-cash or non-operating items included in profit | 20 | **1,441** | 1,534 |
| | | **3,841** | 3,938 |
| Net changes in non-cash working capital | 21 | **(567)** | 855 |
| Deferred revenue | 6 | **172** | 349 |
| Security deposits | 13 | **228** | 124 |
| Post retirement benefits payments | 14 | **(30)** | (30) |
| Changes in regulatory deferral account balances | 4 | **228** | 225 |
| Income taxes paid - current provision | 11 | **(169)** | (59) |
| **Net cash flows from operating activities** | | **3,703** | 5,402 |
| | | | |
| **Cash flows from investing activities** | | | |
| Purchase of property, plant, equipment and intangible assets | 5 | **(2,377)** | (3,549) |
| Proceeds on disposal of property, plant & equipment | | **-** | 218 |
| Interest received | 19 | **12** | 7 |
| **Net cash flows used in investing activities** | | **(2,365)** | (3,324) |
| | | | |
| **Cash flows from financing activities** | | | |
| Repayment of long term debt | 8 | **(525)** | (210) |
| Interest paid | 19 | **(796)** | (786) |
| Dividends paid in cash | | **(480)** | (600) |
| **Net cash flows used in financing activities** | | **(1,801)** | (1,596) |
| Net increase (decrease) in cash and cash equivalents during the year | | **(463)** | 482 |
| Cash and cash equivalents, beginning of the year | | **482** | - |
| **Cash and cash equivalents, end of the year** | | **19** | 482 |

The accompanying notes are an integral part of these financial statements

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 1. CORPORATE INFORMATION

Orillia Power Distribution Corporation ("OPDC or the Company") owns and operates an electricity distribution system, which delivers electricity to approximately 14,200 customers located in Orillia, Ontario. The address of the Company's corporate office and principal place of business is 360 West Street South, Orillia, Ontario, Canada L3V 6J9.

Orillia Power Corporation ("OPC") is the sole shareholder of OPDC. The common shares of OPC are 100% owned by the Corporation of the City of Orillia ("City"), the ultimate parent. The Company was incorporated under the Business Corporations Act (Ontario) on October 26, 2000.

OPDC operates under license issued by the Ontario Energy Board ("OEB"). The Province, through its regulator the OEB, exercises statutory authority through setting or approving all rates charged by the Company and establishing standards of service for the Company's customers. Operating in regulated environment exposes the Company to regulatory and recovery risk (see notes 2.4 through 2.6).

# 2. BASIS OF PREPARATION

## 2.1 Statement of compliance

The Financial Statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee of the IASB.

The Financial Statements were authorized for issue by the Board of Directors on April 24, 2019.

## 2.2 Basis of measurement

The Financial Statements have been prepared on a historical cost basis.

The Financial Statements are presented in Canadian dollars, which is also the Company's functional currency, and all values are rounded to the nearest one thousand dollars, unless when otherwise indicated.

## 2.3 Judgement and Estimates

The preparation of financial statements in compliance with IFRS requires management to make certain critical accounting estimates. It also requires management to exercise judgment in applying the Company's accounting policies. The areas involving critical judgments and estimates in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the financial statements within the next financial year are:

- The recognition and measurement of regulatory deferral account balances (Note 4);
- The determination of impairment of accounts receivable and unbilled energy and distribution revenue; and the incorporation of forward-looking information into the measurement of the expected credit loss (Note 7);
- The determination for the provision for Payment in Lieu of Taxes since there are many transactions and calculations for which the ultimate tax determination is uncertain (Note 11); and
- The calculation of the net future obligation for certain unfunded health, dental and life insurance benefits for the Company's retired employees (Note 14).

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

## 2. BASIS OF PREPARATION (continued)

### 2.4 Explanation of activities subject to rate regulation

The Ontario government enacted the Energy Competition Act, 1998 (“ECA”), to introduce competition to the Ontario energy market. The OEB was granted a legislative mandate including broad powers relating to licensing, standards of conduct and service quality and the regulation of rates charged by the Company and other electricity distributors in Ontario.

OPDC as an electricity distributor, is licensed and regulated by the OEB. The OEB exercises statutory authority through setting or approving all rates charged by the distribution company and establishing standards of service quality for its customers. The Company’s distribution rates are set by the OEB on an annual basis for May 1 to April 30.

### 2.5 Regulatory risk

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

### 2.6 Recovery risk

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

### 2.7 Potential sale of OPDC

The City and Orillia Power Corporation signed a share purchase agreement (“SPA”) with Hydro One Inc. (“Hydro One”) to sell OPDC on August 15, 2016 subject to review and approval by the OEB. On September 27, 2016, Hydro One filed an application with the OEB requesting approval to acquire all of the shares of the Company. On April 12, 2018 the OEB issued its decision denying the application. Hydro One subsequently filed a second application including new evidence on September 26, 2018 with the OEB. The application review process is ongoing.

Should the OEB approve the sale to Hydro One, the SPA provides for timelines to close within three months of approval with a transitional period to follow of six to nine months for assimilation of OPDC operations into Hydro One. Should the OEB not approve the sale, the Company would continue to operate status quo providing distribution services to Orillia.

### 2.8 Comparative Figures

Certain comparative figures have been reclassified to conform to the financial statement presentation adopted for the current year.

(in thousands of Canadian dollars unless otherwise noted)

## 3. ADOPTION OF NEW ACCOUNTING STANDARDS

Accounting standards, interpretations and amendments effective for accounting years beginning on or after January 1, 2018 did not materially affect the Company's financial statements other than those described below.

### 3.1 IFRS 9 Financial instruments ("IFRS 9")

On January 1, 2018, the Company adopted IFRS 9 Financial Instruments, which supersedes IAS 39, Financial Instruments: Recognition and Measurement ("IAS 39"). IFRS 9 includes revised guidance on the classification and measurement of financial assets and liabilities; new guidance for measuring impairment on financial assets; and new hedge accounting guidance. The Company adopted IFRS 9 retrospectively. The Company is not required, upon initial application, to restate comparatives.

***Classification and measurement of financial instruments***

On adoption of IFRS 9, in accordance with transitional provisions, the Company has not restated prior periods but has reclassified the financial assets held at January 1, 2018, retrospectively, based on the new classification requirements and the characteristics of each financial instrument as at the transition date. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements. The Company did not choose the option of designating any financial liabilities at fair value through profit or loss ("FVTPL") as such, the adoption of IFRS 9 did not impact the Company's accounting policies for financial liabilities. Under IFRS 9, financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows. IFRS 9 contains three primary measurement categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVTOCI"), and FVTPL.

The following table shows the original classification and carrying amount under IAS 39 and the new classification and carrying amount under IFRS 9 for each class of the Company's financial assets and financial liabilities as at January 1, 2018:

| **Financial Instrument** | **IAS 39** | | **IFRS 9** | |
|---|---|---|---|---|
| **Financial assets** | | **$** | | **$** |
| Cash and cash equivalents | Loans and receivables | **482** | Amortized cost | 482 |
| Accounts receivable | Loans and receivables | **3,664** | Amortized cost | 3,664 |
| Unbilled energy and distribution revenue | Loans and receivables | **3,597** | Amortized cost | 3,597 |
| Due from related parties | Loans and receivables | **646** | Amortized cost | 646 |
| **Financial liabilities** | | | | |
| Bank indebtedness | Other financial liabilities | **5,000** | Amortized cost | 5,000 |
| Accounts payable and accrued liabilities | Other financial liabilities | **6,837** | Amortized cost | 6,837 |
| Payments in lieu of taxes payable | Other financial liabilities | **631** | Amortized cost | 631 |
| Security deposits | Other financial liabilities | **858** | Amortized cost | 858 |
| Due to related parties | Other financial liabilities | **122** | Amortized cost | 122 |
| Long term debt | Other financial liabilities | **10,287** | Amortized cost | 10,287 |

***Hedge Accounting***

The new hedge accounting model which replaces hedge accounting guidance in IAS 39 did not impact the Company's financial statements as it did not have any hedges in place to mitigate perceived risks.

## 3. ADOPTION OF NEW ACCOUNTING STANDARDS (continued)

### 3.1 IFRS 9 Financial instruments (“IFRS 9”) (continued)

***Disclosure***

Amendments were also made to IFRS 7 introducing expanded qualitative and quantitative disclosures related to IFRS 9, which the Company has also adopted for the annual period beginning January 1, 2018.

***Impact of adopting IFRS 9 on the Company’s financial statements.***

Adoption of IFRS 9 did not result in any significant changes to the Company’s financial statements from past practice.

### 3.2 IFRS 15 Revenue from Contracts with Customers (“IFRS 15”)

On January 1, 2018, the Company adopted IFRS 15 Revenue from Contracts with Customers. IFRS 15 contains a five-step model that applies to contracts with customers that specifies that revenue is recognized when or as an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. Depending on whether certain criteria are met, revenue is recognized at a point in time or over time. The Company adopted IFRS 15 using the modified retrospective approach, with recognition of transitional adjustments in opening retained earnings on the date of initial application (January 1, 2018), without restatement of comparative figures. The adoption of IFRS 15 had no impact to opening retained earnings as at January 1, 2018.

***Recognition and measurement***

Electricity sales are based on the cost of power and usage by the customer. For Regulated Price Plan (“RPP”) customers, the OEB has set a fixed rate which is intended to approximate the true cost of power. The Company recovers the difference between amounts billed to RPP customers for electricity changes (“RPP rate”) and the cost to purchase the electricity (“RPP Settlement Amount”) from the IESO. In accordance with IFRS 15, revenue is recognized at the transaction price as per the contract with the customer. The contract with a RPP customer states the transaction price as the OEB RPP rate. As such, the RPP Settlement Amount will be recorded as a reduction/addition from/to purchased power.

Capital contributions received from developers to construct or acquire property, plant and equipment for the purpose of connecting future customers to the distribution network are considered out of scope of IFRS 15. Capital contributions received will be recognized as contributions in aid of construction and amortized into revenue at an equivalent rate to that used for depreciation of the related property, plant and equipment (PP&E).

***Disclosure***

Amendments were also made to IFRS 15 introducing expanded qualitative and quantitative disclosures, which the Company has also adopted for the annual period beginning January 1, 2018.

***Impact of adopting IFRS 15 on the Company’s financial statements.***

Adoption of IFRS 15 did not result in any significant changes to the Company’s financial statements from past practice.

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 4. REGULATORY DEFERRAL ACCOUNT BALANCES

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

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

Regulatory deferral account balances can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the Company in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Energy Competition Act and deferred in anticipation of their future recovery (payment) from (to) distribution customers.

Regulatory deferral account balances are recognized and measured initially and subsequently at cost. Management continually assesses the likelihood of recovery of regulatory deferral account debit balances. All amounts deferred are subject to approval and potential adjustment by the regulator, the Ontario Energy Board. In assessing the proper accounting treatment and determining the future disposition of regulatory deferral account debit and credit balances, OPDC considers historical industry precedent and follows the latest available and reliable guidance as well as direction through written orders issued by the regulator. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

Remaining recovery periods are those expected, and the actual recovery or settlement periods could differ based on OEB approval. Carrying charges are applied to deferral variance accounts unless indicated otherwise using simple interest at the rate prescribed by the OEB applied to monthly opening balances in the account exclusive of accumulated interest.

### 4.1 Regulatory deferral account balances net of deferred income tax impacts

Due to previous, existing or expected future regulatory articles or decisions, OPDC has the following amounts expected to be recovered by customers (returned to customers) in future periods and as such regulatory deferral account balances are presented on the statement of financial position net of deferred tax impacts:

| Regulatory deferral account balances | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES NET OF DEFERRED TAXES** | | |
| Regulatory deferral account debit balances | **2,000** | 1,980 |
| Less deferred tax impact | **530** | 525 |
| | **1,470** | 1,455 |
| | | |
| **REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES NET OF DEFERRED TAXES** | | |
| Regulatory deferral account credit balances | **4,124** | 3,284 |
| Less deferred tax impact | **1,093** | 870 |
| | **3,031** | 2,414 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

## 4.2 Regulatory deferral account impacts on Statements of Comprehensive Income and Cash Flows

The following schedule summarizes the net movement in regulatory deferral account balances adjusted for related deferred tax impacts included in the Statement of Comprehensive Income and reducing profit for the year:

| Net movement in regulatory deferral account balances including related deferred taxes | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Regulatory debit reallocated from other income - change in PP&E useful lives | **(693)** | (694) |
| Retail settlement variances between energy purchased and recovered from customers | **(38)** | (97) |
| Lost revenue adjustment reallocated from other revenue | **153** | 239 |
| Amortization of stranded meters reallocated from other revenue | **(34)** | (34) |
| Regulatory interest and other | **20** | 21 |
| Net movement in regulatory deferral account balances before related deferred taxes | **(592)** | (565) |
| Deferred taxes related to changes in regulatory deferral account balances | **218** | 209 |
| | **(374)** | (356) |

All of the above amounts are non-cash accruals added back to profit in order to arrive at cash flows from operating activities on the Statement of Cash Flows (see Note 20).

The following schedule summarizes the net movement in regulatory deferral account balances impacting cash and included in the investing activities section of the Statement of Cash Flows:

| Changes in regulatory deferral account balances on cash flow statement | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **NET REGULATORY DEFERRAL ACCOUNT BALANCES** | | |
| Regulatory deferral account debit balances | **2,000** | 1,980 |
| Regulatory deferral account credit balances | **(4,124)** | (3,284) |
| **Net regulatory deferral account debit (credit) balances** | **(2,124)** | (1,304) |
| | | |
| **CHANGES IN REGULATORY DEFERRAL ACCOUNT BALANCES (CASH FLOW STATEMENT)** | | |
| Net change in regulatory deferral account debit (credit) balances | **820** | 789 |
| Net movement in regulatory deferral account balances before related deferred taxes | **(592)** | (565) |
| Other | **-** | 1 |
| **Changes in regulatory deferral account balances - cash flow** | **228** | 225 |
| | | |
| **RECONCILED TO ABOVE AS FOLLOWS:** | | |
| Disposition of approved regulatory deferral account balances | **228** | 228 |
| Interim disposition of account 1576 balance | **-** | (4) |
| Other | **-** | 1 |
| **Changes in regulatory deferral account balances - cash flow** | **228** | 225 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

## 4.3 Detail for regulatory deferral account balances

Regulatory deferral account debit balances are comprised of the following accounts:

| Regulatory deferral account debit balances | | 2018 | 2017 |
|---|---|---|---|
| | Account #'s | $ | $ |
| Low voltage | 1550 | **1,312** | 1,392 |
| Stranded meter capital | 1555 | **172** | 206 |
| Lost revenue variance | 1568 | **402** | 242 |
| Network services - transmission | 1584 | **-** | 5 |
| Connection services - transmission | 1586 | **-** | 19 |
| Global adjustment | 1589 | **-** | 24 |
| Disposition / recoveries | 1595 | **64** | 54 |
| Other | | **50** | 38 |
| | | **2,000** | 1,980 |

Regulatory deferral account credit balances are comprised of the following accounts:

| Regulatory deferral account credit balances | | 2018 | 2017 |
|---|---|---|---|
| | Account #'s | $ | $ |
| Retail costs | 1518 / 1548 | **70** | 69 |
| Smart meter entity | 1551 | **15** | 9 |
| IFRS - CGAAP Transitional PP&E amounts | 1575 | **14** | 14 |
| Change in PP&E useful lives estimates | 1576 | **2,593** | 1,900 |
| Wholesale market services | 1580 | **861** | 1,073 |
| Network services - transmission | 1584 | **62** | - |
| Connection services - transmission | 1586 | **94** | - |
| Power | 1588 | **364** | 219 |
| Global adjustment | 1589 | **51** | - |
| | | **4,124** | 3,284 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

## 4.4 Continuity schedules for regulatory deferral account balances

A continuity schedule for regulatory deferral account debit balances from 2017 to 2018 follows below:

| Regulatory deferral account debit balances | Est. Years to recover or reverse | December 31 2018 | Recovery / reversal | Balances arising in the period | December 31 2017 |
|---|---|---|---|---|---|
| | | $ | | | $ |
| Low voltage | 1 - 4 | **1,312** | (674) | 594 | 1,392 |
| Stranded meter capital | 1 - 4 | **172** | (34) | - | 206 |
| Lost revenue variance | 1 - 4 | **402** | - | 160 | 242 |
| Network services - transmission | 1 - 4 | **-** | (5) | - | 5 |
| Connection services - transmission | 1 - 4 | **-** | (19) | - | 19 |
| Global adjustment | 1 - 4 | **-** | (24) | - | 24 |
| Disposition / recoveries | 1 | **64** | (228) | 238 | 54 |
| Other | 1 - 4 | **50** | - | 12 | 38 |
| | | **2,000** | (984) | 1,004 | 1,980 |

A continuity schedule for regulatory deferral account credit balances from 2017 to 2018 follows below:

| Regulatory deferral account credit balances | Est. Years to recover or reverse | December 31 2018 | Recovery / reversal | Balances arising in the period | December 31 2017 |
|---|---|---|---|---|---|
| | | $ | | | $ |
| Retail costs | 1 - 4 | **70** | - | 1 | 69 |
| Smart meter entity | | **15** | (4) | 10 | 9 |
| IFRS - CGAAP Transitional PP&E amounts | 1 - 4 | **14** | - | - | 14 |
| Change in PP&E useful lives estimates | 1 - 4 | **2,593** | - | 693 | 1,900 |
| Wholesale market services | 1 - 4 | **861** | (448) | 236 | 1,073 |
| Network services - transmission | | **62** | 88 | (26) | - |
| Connection services - transmission | 1 - 4 | **94** | 97 | (3) | - |
| Power | 1 - 4 | **364** | (113) | 258 | 219 |
| Global adjustment | | **51** | (105) | 156 | - |
| | | **4,124** | (485) | 1,325 | 3,284 |

## 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

### 4.5 Description of regulatory deferral account balances

A description of the nature of the regulatory deferral account debit and credit balances listed in the schedules are described below referenced by account number.

*Account 1518 - Retail Cost Variance Account – Services*

This account records the net of revenue derived from establishing retail service agreements, distributor-consolidated and retailer-consolidated billing and the costs of entering into retail service agreements and related administration, monitoring and other expenses necessary to maintain the contract, as well as the incremental costs incurred and any avoided costs credits to provide the related billing services.

*Account 1548 - Retail Cost Variance Account – STR*

This account records the net of revenue derived from service transaction requests (“STR”) in the form of a request fee, processing fee, and information request fee and the incremental cost of labour, internal information system maintenance costs and delivery costs related to the provision of these services.

*Account 1550 – Low Voltage Charges Variance Account*

This account records the net of revenue derived from amounts billed to customers through an OEB-approved rate for low voltage services and the amounts paid to Hydro One Networks Inc. (“Networks”) for the related low voltage services provided to the Company.

*Account 1555 – Stranded Meters Account*

Conventional meters were replaced by smart meters during the smart meter deployment from 2009 to 2011 and the Company recorded the disposition of these stranded assets in PP&E and a regulatory deferral debit balance in accordance with OEB Guidelines. This account records the net book value of the stranded conventional meters, to be amortized to depreciation expense until the next cost of service rate application. Carrying charges are not applied to this account.

*Account 1568 – LRAM Variance Account*

The OEB established a Lost Revenue Adjustment Mechanism variance account (“LRAMVA”) to capture the differences between the results of actual, verified impacts of authorized Conservation and Demand Management (“CDM”) activities undertaken by electricity distributors under the Legacy CDM Framework (2011 to 2014) and the Conservation First Framework (2015 to 2020) net of the level of CDM program activities included in the distributor’s load forecast (i.e. the level embedded into rates). Lost revenues are recorded annually and are included in the net movement in regulatory deferral account balances on the statement of comprehensive income. The OEB approved the disposition of an LRAMVA debit balance of $394 related to CDM programs up to December 31, 2015 in its Decision and Order for rates effective May 1, 2017 issued on March 30, 2017.

## 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

### 4.5 Description of regulatory deferral account balances (continued)

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

This account records the PP&E difference arising as a result of an accounting policy change recognizing capital contributions as deferred revenue upon transition from previously adopted Canadian Generally Accepted Accounting Principles ("CGAAP") to IFRS on January 1, 2014. The balance in this account represents the amortization of the transition year capital contributions previously expensed in 2014. The associated net book value is recorded as deferred revenue and will be amortized to income over a period that matches the remaining useful lives of the related PP&E. Carrying charges are not applied to this account.

*Account 1576 – Accounting Changes under CGAAP*

This account records the financial differences arising as a result of changes the Company made to accounting depreciation under CGAAP effective January 1, 2013. OPDC adopted new asset useful lives based on the 2010 "Kinectric's Report", part of an asset depreciation study initiated by the OEB for use by electricity distributors. Carrying charges are not applied to this account.

OPDC filed an application on October 19, 2015 for 2016 distribution rates (EB-2015-0286) related to the disposition of the regulatory deferral credit balance in account 1576 as of December 31, 2014. On January 14, 2016, the OEB approved on an interim basis the disposition of regulatory deferral credit of $1,481 over a one year period January 1, 2016 to December 31, 2016. The balance approved for disposition included a rate of return component of $96 calculated according to OEB filing requirements, reducing operating revenue on the statement of comprehensive income.

*Account 1580 – Retail Settlement Variance Account - Wholesale Market Services*

This account records the net of revenue derived from amounts billed to consumers through an OEB-approved rate for the cost of services required to operate the provincial electricity system and run the wholesale market and the amounts paid to the IESO for these system costs.

*Account 1584 – Retail Settlement Variance Account – Retail Transmission Network Services*

This account records the net of revenue derived from amounts billed to consumers through an OEB-approved rate for retail transmission network services and the amounts paid to Networks for the related network costs.

*Account 1586 – Retail Settlement Variance Account – Retail Transmission Connection Services*

This account records the net of revenue derived from amounts billed to consumers through an OEB-approved rate for retail transmission connection services and the amounts paid to Networks for the related connection costs.

*Account 1588 – Retail Settlement Variance Account – Power*

This account records the net of revenue derived from amounts billed to consumers for electricity costs and the amounts paid to the IESO and embedded generators for electricity purchased. OPDC purchases power on behalf of the customer and passes these costs on to the customer with no markup. This account captures variances due to theft of power and unaccounted-for energy as well as the difference between estimated and actual distribution line losses.

*Account 1589 – Retail Settlement Variance Account – Global Adjustment*

This account records the net of revenue derived from amounts billed to non-Regulated Price Plan ("non-RPP") consumers for global adjustment costs and an allocation of amounts paid to the IESO for global adjustment charged on electricity purchased for non-RPP consumers. This account captures variances due to the timing of bills and difference between global adjustment rates billed to consumers and final charges billed to the Company each month.

## 4. REGULATORY DEFERRAL ACCOUNT BALANCES (continued)

### 4.5 Description of regulatory deferral account balances (continued)

*Account 1595 – Disposition of Regulatory Account Balances*

This account records the net of the disposition of regulatory deferral account balances approved for recovery (or refund) in rates as part of the regulatory process and the amounts recovered (or refunded) through OEB-approved regulatory deferral account rate riders from the following OEB applications:

OPDC filed an IRM application on October 31, 2016 for 2017 distribution rates (EB-2016-0321). On March 30, 2017, the OEB approved the disposition of regulatory deferral account debit balances of $890 and regulatory deferral account credit balances of $1,136 over a one year period May 1, 2017 to April 30, 2018. The net disposition balance of $246 consisted of principal balances as of December 31, 2015, with carrying charges projected to April 30, 2017.

OPDC filed an IRM application on October 16, 2017 for 2018 distribution rates (EB-2017-0264). On March 22, 2018, the OEB approved the disposition of regulatory deferral account debit balances of $883 and regulatory deferral account credit balances of $646 over a one-year period May 1, 2018 to April 30, 2019. The net disposition balance of $237 consisted of principal balances as of December 31, 2016, with carrying charges projected to April 30, 2018.

### 4.6 2019 Rate Application

OPDC filed an IRM application on November 5, 2018 for 2019 distribution rates (EB-2018-0061). The Company did not seek disposition of regulatory deferral account balances in the application which was approved March 28, 2019.

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 5. PROPERTY, PLANT, EQUIPMENT & INTANGIBLES

Property, plant and equipment (“PP&E”) are recognized at cost, being the purchase price and directly attributable cost of acquisition or construction required to bring the asset to the location and condition necessary to be capable of operating in the manner intended by the Company, including eligible borrowing costs.

Depreciation of PP&E and amortization of intangibles is recorded in the Statement of Comprehensive Income on a straight-line basis over the estimated useful life of the related asset. The estimated useful lives, residual values and depreciation methods are reviewed at the end of each annual reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

*The estimated useful lives for PP&E and intangibles are as follows:*

| | |
|---|---|
| Buildings and fixtures | 10 - 50 years |
| Substations | 15 - 60 years |
| Sub-transmission lines | 45 - 60 years |
| Distribution system (poles, wires, transformers) | 40 - 60 years |
| Smart meters | 15 years |
| Other capital assets | 15 - 20 years |
| Land | not depreciated |
| Land rights | 40 years |
| Computer software | 5 years |

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

Major spares such as spare transformers and other items kept as standby/back up equipment are accounted for as PP&E since they support the Company’s distribution system reliability.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount net of payments to the developer recognized as deferred revenue (contributions in aid of construction).

Gains and losses on disposal of an item of PP&E are determined by comparing the net proceeds from disposal with the carrying amount of the asset and are included in the Statement of Comprehensive Income when the asset is disposed of. When an item of PP&E with related contributions in aid of construction is disposed, the remaining deferred revenue is recognized in full in the Statement of Comprehensive Income.

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

OPDC conducts annual internal assessments of the values of PP&E, intangible assets and regulatory deferral account debit balances to determine whether there are events or changes in circumstances that indicate that their carrying amount may not be recoverable. Where the carrying value exceeds its recoverable amount, which is the higher of value in use and fair value less costs to sell, the asset is written down accordingly.

Where it is not possible to estimate the recoverable amount of an individual asset, the impairment test is carried out on the asset's cash-generating unit, which is the lowest group of assets to which the asset belongs for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets. The entire Company is considered one cash-generating unit for which impairment testing is performed. An impairment loss is charged to the Statement of Comprehensive Income, except to the extent it reverses gains previously recognized in other comprehensive income.

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 5. PROPERTY, PLANT, EQUIPMENT & INTANGIBLES (continued)

| Property, plant, equipment and intangibles | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **COST** | | |
| Balance, beginning of year | **34,476** | 31,258 |
| Purchase of property, plant and equipment | **2,358** | 3,541 |
| Purchase of intangibles | **19** | 8 |
| Disposals | **(131)** | (331) |
| **Balance, end of year** | **36,722** | 34,476 |
| **ACCUMULATED AMORTIZATION** | | |
| Balance, beginning of year | **4,185** | 3,203 |
| Depreciation of property plant and equipment | **1,196** | 1,154 |
| Amortization of intangibles | **27** | 33 |
| Disposals | **(72)** | (205) |
| **Balance, end of year** | **5,336** | 4,185 |
| **CARRYING AMOUNTS** | | |
| Balance, beginning of year | **30,291** | 28,055 |
| Purchase of property, plant, equipment and intangibles | **2,377** | 3,549 |
| Depreciation and amortization | **(1,223)** | (1,187) |
| Disposals | **(59)** | (126) |
| **Balance, end of year** | **31,386** | 30,291 |
| **SUMMARY OF CARRYING AMOUNTS BY CATEGORY** | | |
| Land and buildings | **1,036** | 1,060 |
| Distribution plant and equipment | **29,672** | 28,632 |
| Other | **510** | 538 |
| Intangibles | **53** | 61 |
| Work in progress | **115** | - |
| **Balance, end of year** | **31,386** | 30,291 |

The amount of impairment loss that has been provided as at December 31, 2018 for PP&E is $NIL (December 31, 2017 – $NIL).

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 6. REVENUE RECOGNITION AND DEFERRED REVENUE

***Revenue recognition***

Revenue is recognized to the extent that it is probable that economic benefits will flow to the Company and that the revenue can be reliably measured. Revenue is comprised of recovered energy purchases, distribution of energy, pole use rental, collection charges, investment income and other miscellaneous revenues.

OPDC is licensed by the OEB to distribute electricity. As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. OPDC is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers. OPDC has determined that they are acting as a principal for the electricity distribution and, therefore, have presented the electricity revenues on a gross basis.

Revenue from recovered energy purchases and distribution of electricity is recognized on an accrual basis, including revenue accrued in respect of electricity delivered but not yet billed. Recovered energy purchases and distribution of energy revenue is comprised of customer billings based on actual monthly meter readings.

Other revenues, which include revenues from pole use rental, collection charges, contributions in aid of construction and other miscellaneous revenues are recognized at the time services are provided.

| Revenue | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Recovered energy purchases | **36,463** | 36,974 |
| Distribution revenue | **8,418** | 8,216 |
| Other revenue | **491** | 532 |
| Total operating revenue | **8,909** | 8,748 |
| **Total revenue** | **45,372** | 45,722 |

***Deferred revenue***

Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements.

Since the contributions in aid of construction will provide customers with ongoing access to the supply of electricity, these contributions are classified as deferred revenue and are recognized into other revenue on a straight-line basis over the useful life of the constructed or contributed asset. When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction. The continuity of deferred contributions in aid of construction is as follows:

| Deferred revenue | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Balance, beginning of year | **1,830** | 1,526 |
| Contributions in aid of construction received | **172** | 349 |
| Contributions in aid of construction amortized to other revenue | **(53)** | (45) |
| **Balance, end of year** | **1,949** | 1,830 |

(in thousands of Canadian dollars unless otherwise noted)

## 7. ACCOUNTS RECEIVABLE AND UNBILLED ENERGY AND DISTRIBUTION REVENUE

***Recognition and initial measurement***

The Company initially recognizes accounts receivable on the date on which they are originated and unbilled energy and distribution revenue ("unbilled revenue") on the date on which the Company delivers the electricity but has not yet billed the customer. Accounts receivable and unbilled revenue are initially measured at fair value.

***Classification and subsequent measurement***

Accounts receivable and unbilled revenue are classified and subsequently measured at amortized cost, using the effective interest rate method. The carrying amount is reduced using a loss allowance and the amount of the related loss allowance is recognized in profit or loss. Subsequent recoveries of receivables and unbilled revenue previously provisioned are credited to profit or loss.

***Fair value measurement***

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

***Credit risk***

Credit risk associated with accounts receivable and unbilled revenue is managed through the collection of security deposits, credit insurance and by way of arrears management plans and other financial assistance programs in accordance with OEB directives. Programs include the Ontario Electricity Support Program (OESP) and the Low-Income Energy Assistance Program (LEAP). Deposits collected and to be refunded to customers or developers within the next fiscal year are classified as a current liability (Note 13). Interest rates paid on customer deposits are based on the TD Bank's prime business rate less 2.0%.

The Company's credit risk associated with accounts receivable and unbilled revenue is primarily related to payments from electric distribution customers. The Company has approximately 14,200 customers, the majority of which are residential. The Company considers an account receivable to be in default when the customer is unlikely to pay its credit obligations in full, without recourse by the Company, such as realizing security (if any is held). Accounts are in default when the customers have failed to make payments when due, which is generally within 30 days of the billing date.

Unbilled revenue is normally billed within 30 days and then becomes part of accounts receivable for loss allowance calculation purposes The following table provides information about the exposure to credit risk and ECLs for accounts receivable by level of delinquency:

| | **2018** | | | 2017 | | |
|---|---|---|---|---|---|---|
| | **Gross** | **Loss Allowance** | **Net** | Gross | Loss Allowance | Net |
| 0 - 60 days | **4,248** | **(16)** | **4,232** | 3,402 | (6) | 3,396 |
| 61 - 90 days | **15** | **(2)** | **13** | 31 | (5) | 26 |
| Over 90 days | **647** | **(59)** | **588** | 300 | (58) | 242 |
| | **4,910** | **(77)** | **4,833** | 3,733 | (69) | 3,664 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 7. ACCOUNTS RECEIVABLE AND UNBILLED ENERGY AND DISTRIBUTION REVENUE

(continued)

| Accounts receivable | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Due from distribution customers | **3,703** | 3,106 |
| Recoverable work | **589** | 257 |
| Provincial programs and rebates | **435** | 290 |
| Other | **183** | 80 |
| | **4,910** | 3,733 |
| Loss allowance | **(77)** | (69) |
| | **4,833** | 3,664 |
| **ACCOUNTS RECEIVABLES BY AGE** | | |
| 0 - 60 days | **4,248** | 3,402 |
| 61 - 90 days | **15** | 31 |
| Over 90 days | **647** | 300 |
| | **4,910** | 3,733 |
| **CONTINUITY OF LOSS ALLOWANCE** | | |
| Balance, beginning of year | **(69)** | (78) |
| Provision for credit loss | **(77)** | (83) |
| Written off | **69** | 92 |
| **Balance, end of year** | **(77)** | (69) |

***Unbilled energy and distribution revenue***

Unbilled revenue represents amounts for which the Company has a contractual right to receive cash through future billings and are unbilled at year end. Accounts are billed on a monthly basis based on power consumed in the previous month. The amount of the loss allowance that has been provided as at December 31, 2018 for unbilled revenue is $12 (December 31, 2017 – $NIL).

| Unbilled energy and distribution revenue | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Unbilled energy and distribution revenue | **3,523** | 3,597 |
| Loss allowance | **(12)** | - |
| | **3,511** | 3,597 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 8. LONG TERM DEBT

***Promissory note payable to the City***

The promissory note payable to the City bears interest for the current year at 6.25% per annum (2017 – 6.25%). Interest payments are required to be made quarterly on the last day of March, June, September and December. The promissory note is due December 31, 2030 and payments to the City of Orillia are interest only. Under the terms of the note, the City of Orillia can demand repayment of up to 20% of the original principal in a calendar year with the payment to be made March 31 provided the City gives six months' notice to OPDC. No such demand has been made by the City as of the date of approval of these financial statements. The fair value of the note at current market borrowing rates approximates $11,151 (2017 - $11,193). The note is secured by a general security agreement on all the assets of the Company. Should the OEB approve the sale of the Company to Hydro One, the promissory note to the City will be repaid prior to the closing date of the sale.

***Debenture payable to Infrastructure Ontario ("OIPC")***

OPDC had previously entered into debenture financing with OIPC to fund its smart meter infrastructure expenditures. On May 3, 2010 a debenture in the amount of $2,100 was issued based on a 10-year term and an annual interest rate of 4.39%. OPDC incurred $4 (2017 - $39) in interest expense to OIPC in 2018. Under the terms of the debenture, the Company was required to make principal repayments of $210 annually, until debenture retirement in 2020. In February 2018, the balance of the debenture was retired. Consequently, the fair value of the debenture at current market borrowing rates was $NIL (2017 - $539).

***Debt obligations repayable within the next five years***

The following table summarizes the Company's outstanding long term debt obligations including principal to be repaid within the next five years (assuming that no repayment is demanded on the promissory note by the City within the timeframe outlined):

| Long term debt | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Promissory note due to the City | **9,762** | 9,762 |
| Debenture payable to Ontario Infrastructure Projects Corporation ("OIPC") | **-** | 525 |
| | **9,762** | 10,287 |
| Current portion of debenture payable to OIPC | **-** | 210 |
| | **9,762** | 10,077 |
| | | |
| **Principal repayments anticipated over the next five years and thereafter:** | | |
| 2018 | **-** | **525** |
| 2019 - 2023 | **-** | **-** |
| Thereafter | **9,762** | **9,762** |
| | **9,762** | 10,287 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 9. BANK INDEBTEDNESS

OPDC has executed certain credit facilities currently with a Canadian chartered bank. The facilities are subject to the borrower meeting certain covenant thresholds in order to pay dividends without bank permission. The agreement also includes financial covenants related to debt service coverage ratios and debt to capitalization ratios that must be met by the borrower. OPDC is in compliance with all covenant requirements. Facilities are as follows:

OPDC has a committed revolving operating loan available at the borrower's option by way of prime based loans, banker's acceptances and standby letters of guarantee ("L/G"), utilized to finance ongoing working capital requirements and letter of guarantee requirements. The operating loan is secured by a General Security Agreement on the assets of the Company. Advances are at prime with a standby fee for the unused portion at 0.15%. L/G are issued at a cost of 0.50% per annum.

OPDC has a committed reducing term (multiple draw) loan available at the borrower's option by way of fixed rate terms up to five years and floating prime based loans. Utilized to finance prior year capital expenditures and replenish working capital. The operating loan is secured with a General Security Agreement on the assets of the Company. Cash advances are at prime less 0.25%. Currently, draws on this facility are interest only and have not been locked in to a fixed term or rate.

OPDC has an uncommitted prime based operating loan available at the borrower's option subject to receiving OEB approval of the sale of the utility to Hydro One. The operating loan was established in order to facilitate the payout of the promissory note due to the City of Orillia and the debenture owing to Ontario Infrastructure Projects Corporation prior to the sale closing date.

The following table outlines facilities available and utilized:

| Bank indebtedness | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **AMOUNTS BORROWED AND OUTSTANDING** | | |
| OPDC - revolving operating loan for working capital purposes | **50** | - |
| OPDC - committed reducing term facility for capital expenditures financing | **5,000** | 5,000 |
| | **5,050** | 5,000 |
| **IRREVOCABLE LETTERS OF CREDIT OUTSTANDING** | | |
| OPDC - IESO prudential support power purchase guarantee | **2,035** | 2,035 |
| | **2,035** | 2,035 |
| **BORROWING LIMITS ON CREDIT FACILITIES** | | |
| OPDC - revolving operating loan for working capital purposes | **8,000** | 8,000 |
| OPDC - committed reducing term facility for capital expenditure financing | **5,000** | 5,000 |
| OPDC - uncommitted operating loan pending OEB approval of sale of utility to Hydro One | **10,500** | 10,500 |
| | **23,500** | 23,500 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 10. CAPITAL MANAGEMENT

OPDC considers its capital to be its share capital, retained earnings and accumulated other comprehensive income. OPDC's objectives when managing capital are:

- to safeguard the Company's ability to continue as a going concern, so that it can continue to provide adequate returns for the shareholder and benefits for other stakeholders while maintaining its assets,
- to provide an adequate return to the shareholder by controlling costs and establishing rates that maximize rate of return commensurate with the level of risk, and
- to ensure the capital structure does not prevent the Company from taking advantage of potential growth opportunities provided that they do not expose the Company to unnecessary risk.

OPDC manages its capital structure by monitoring forecasted cash flows over the next five years and makes adjustments to it in light of changes in economic conditions, annual profitability and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company will adjust the amount of dividends paid to the shareholder and borrowings from lenders, subject to the constraints imposed by lending agreements. OPDC is subject to quarterly reporting and bank review of its interest coverage and debt capitalization ratios, in relation to its various bank credit lines.

Consistent with others in the industry, the Company monitors capital on the basis of the debt-to-capital ratio calculated as long term debt divided by the sum of long term debt plus equity, as shown in the following table. For purposes of comparing the measures below to benchmarks, the Company was initially incorporated at a debt to capital ratio of 0.48.

| Debt to capital ratio | 2018 | 2017 |
|---|---|---|
| | **$** | $ |
| **Sum of long term debt and shareholder's equity** | | |
| Long term debt | **9,762** | 10,077 |
| Shareholder's equity | **15,268** | 14,571 |
| | **25,030** | 24,648 |
| **Key Ratio - Long Term Debt to Capital** | | |
| Ratio of debt to debt plus equity | **0.39** | 0.41 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 11. CURRENT AND DEFERRED INCOME TAXES (PILS)

***Tax Status***

Prior to August 15, 2016, the Company was an Municipal Electricity Utility (“MEU”) for purposes of the payments in lieu of taxes (“PILs”) regime contained in the ECA. As an MEU, OPDC was exempt from tax under the Federal Income Tax Act (Canada) and the Corporations Tax Act (Ontario) (“Tax Act”). Under the ECA, the Company was required to make, for each taxation year, PILs to the Ontario Electricity Financial Corporation, commencing October 1, 2001. These payments were calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Act as modified by the ECA, and related regulations.

On August 15, 2016 the Company became party to a share purchase agreement with Hydro One, a company taxable under the Tax Act. Consequently, under section 149(1.1) of the Tax Act, OPDC ceased to be exempt under the ITA as of the date of signing the Share Purchase Agreement. Pursuant to section 149(10) of the Tax Act, as of the date it ceased to be exempt, the Company became liable to pay both federal and provincial income tax, with its first tax year starting at that time.

***Deemed disposition at fair market value***

OPDC has been deemed to have disposed of all assets, and reacquired them, at fair market value for income tax purposes immediately prior to August 15, 2016 and is required to file a final tax return as of August 14, 2016 with the Ministry of Finance for Ontario. As a result of the fair market value “bump” the Company is subject to applicable taxes from income and losses up to this date including the impact of the deemed disposition (“departure taxes”) payable to the Ministry of Finance estimated at $1141.

OPDC is carrying the newly adjusted cost bases for all of its assets forward into the Tax Act regime and will be maintaining a December 31’st year end.

***Current and deferred tax***

Current tax and deferred tax are recognized in comprehensive income except to the extent that it relates to items recognized directly in equity. Current income taxes are recognized for the estimated income taxes payable or receivable on taxable income for the current year and any adjustment to income taxes payable in respect of previous years. Current income taxes are determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date.

Deferred tax assets and liabilities are recognized where the carrying amount of an asset or liability differs from its tax base. The amount of the deferred tax asset or liability is measured at the amount expected to be recovered from or paid to the taxation authorities. This amount is determined using tax rates and tax laws that have been enacted or substantively enacted by the year-end date and are expected to apply when the liabilities / (assets) are settled / (recovered). OPDC recognized deferred tax arising from temporary difference on regulatory deferral account balances, post retirement benefits and PP&E and intangible assets.

Recognition of deferred tax assets for unused tax losses, tax credits and deductible temporary differences is restricted to those instances where it is probable that future taxable profit will be available against which the deferred tax asset can be utilized. At the end of each reporting period, the Company reassesses both recognized and unrecognized deferred tax assets. OPDC recognizes a previously unrecognized deferred tax asset to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

***Judgement required***

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

**NOTES TO THE FINANCIAL STATEMENTS**
For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 11. CURRENT AND DEFERRED INCOME TAXES (PILS) (continued)

### 11.1 Current income tax expense included in Statement of Comprehensive Income

Combined statutory federal and provincial tax rates for Ontario are 26.5% on active business. Income tax expense varies from amounts which would be computed by applying the Company's combined statutory income tax rate as follows:

| Current provision for (recovery of) | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Profit for the year | **1,177** | 1,217 |
| Add back provision for PILs | **247** | 507 |
| | **1,424** | 1,724 |
| Statutory federal and provincial combined rate | **26.5%** | 26.5% |
| Provision for PILs at statutory rates | **377** | 457 |
| Increase (decrease) in PILs resulting from differences in tax base vs carrying values: | | |
| PP&E and intangibles | **(96)** | (448) |
| Departure tax estimate due to exit from PILs regime - August 14, 2016 | **(50)** | (73) |
| Other | **(62)** | 123 |
| | **169** | 59 |

### 11.2 Payment in lieu of taxes payable

| Payments in lieu of taxes payable (PILS) | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| PILs payable | **800** | 631 |
| | **800** | 631 |

### 11.3 Deferred income tax expense included in Statement of Comprehensive Income

| Deferred provision | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **Included in profit for the year** | | |
| PP&E and intangibles | **413** | 201 |
| Goodwill estimated as a result of exiting PILs tax regime on SPA signing | **(317)** | 247 |
| Other | **(18)** | - |
| | **78** | 448 |
| **Included in net movement in regulatory deferral account balances** | | |
| Deferred taxes related to changes in regulatory deferral account balances | **(218)** | (209) |
| | **(218)** | (209) |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 11. CURRENT AND DEFERRED INCOME TAXES (PILS) (continued)

### 11.4 Deferred income tax assets

Deferred income tax assets are provided for temporary differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases. The following table outlines the Company's position with respect to deferred tax assets. The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences. OPDC believes that this asset should be recognized as it will be utilized through future activities.

| Deferred income tax asset (liability) | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **Asset (liability) due to excess (shortfall) of tax basis over carrying values** | | |
| PP&E | **(259)** | 155 |
| Goodwill estimated as a result of exiting PILs tax regime on SPA signing | **2,284** | 1,966 |
| Post retirement benefits | **153** | 153 |
| Sick pay accrual | **32** | 32 |
| Non-capital loss carry forward | **18** | - |
| | **2,228** | 2,306 |

### 11.5 Deferred tax balances related to regulatory deferral account balances

Deferred tax balances related to regulatory deferral account debit and credit balances are netted against the applicable regulatory deferral account debit or credit balances. They are not included with the other deferred income tax asset balances related to PP&E, intangibles, post retirement benefits and loss carry forward.

| Deferred income tax assets (liabilities) included with regulatory deferral account balances | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **Asset (liability) due to excess (shortfall) of tax basis over carrying values:** | | |
| Asset included with regulatory deferral account credit balances | **1,093** | 870 |
| Liability included with regulatory deferral account debit balances | **(530)** | (525) |
| | **563** | 345 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| Accounts payable and accrued liabilities | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Power purchases | **2,478** | 3,059 |
| Accounts payable and accrued liabilities | **2,352** | 2,395 |
| Customer credit balances | **1,479** | 1,383 |
| | **6,309** | 6,837 |

Due to its short-term nature, the carrying amount of the accounts payable and accrued liabilities approximates its fair values.

## 13. SECURITY DEPOSITS

Customers and developers may be required to post security to obtain electricity or other services, which are refundable. Security posted in the form of cash or cash equivalents, represents cash deposits from electricity distribution customers and retailers, as well as construction deposits from developers.

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

Construction deposits are refundable upon completion of the capital project and an economic evaluation as prescribed in the Distribution System Code based on actual capital costs. The economic evaluation will determine the timing and amount of deposits to be refunded to developers.

Where the security posted is in the form of cash or cash equivalents, these amounts are recorded in the accounts as customer and developer security deposits. Interest rates paid on customer and developer deposits are based on the TD Bank's prime business rate less 2%.

| Security deposits | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Customer deposits | **538** | 450 |
| Developer deposits | **1,201** | 408 |
| | **1,739** | 858 |
| Allocated to: | | |
| Current | **915** | 262 |
| Long term | **824** | 596 |
| | **1,739** | 858 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 14. POST RETIREMENT BENEFITS

***Defined contribution plan***

The employees of the Company participate in the Ontario Municipal Employees Retirement System ("OMERS"). OPDC also makes contributions to the OMERS plan on behalf of its employees. The plan has a defined benefit option at retirement available to some employees, which specifies the amount of the retirement benefit plan to be received by the employees based on length of service and rates of pay. OPDC is only one of a number of employers that participates in the plan and the financial information provided to the Company on the basis of the contractual agreements is insufficient to measure the Company's proportionate share in the plan assets and liabilities on defined benefit accounting requirements. As insufficient information is available to account for the plan as a defined benefit plan, the contribution payable in exchange for services rendered during a period is recognized as an expense during that period.

The employer portions of amounts paid to OMERS made for current service and recognized in comprehensive income are as follows:

| Contributions to OMERS on behalf of employees | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **Contributions to OMERS on behalf of employees** | **294** | 326 |

***Defined benefit plans***

OPDC provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees through a group defined benefit plan. The costs of this plan and net obligation are calculated by estimating the amount of future benefits that are expected to be paid out discounted to determine its present value. Any unrecognized past service costs are deducted.

The calculation is performed by a qualified actuary using the projected unit credit method every third year or when there are significant changes to workforce. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

Defined benefit obligations are measured using the projected unit credit method discounted to its present value using yields available on high quality corporate bonds that have maturity dates approximating to the terms of the liabilities. Remeasurements of the defined benefit obligation include actuarial gains and losses and are recognized directly within equity in other comprehensive income. Service costs are recognized in the Statement of Comprehensive Income in operating expenses and include current and past service costs as well as gains and losses on curtailments.

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

The plan is exposed to several risks, including:

- Interest rate risk: decreases/increases in the discount rate used (high quality corporate bonds) will increase/decrease the defined benefit obligation.
- Longevity risk: changes in the estimation of mortality rates of current and former employees.
- Health care cost risk: increases in cost of providing health, dental and life insurance benefits.

(in thousands of Canadian dollars unless otherwise noted)

## 14. POST RETIREMENT BENEFITS (continued)

***Defined benefit plan*** (continued)

The accrued benefit liability and the expense for the year ended December 31, 2018 were based on results and assumptions determined by actuarial valuation as at December 31, 2016 are as follows:

| Post-retirement benefits | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Defined benefit obligation, beginning of year | **578** | 578 |
| Amounts recognized in profit for the year | | |
| Current service costs | **8** | 8 |
| Finance costs on obligation | **22** | 22 |
| | **30** | 30 |
| Benefit payments | **(30)** | (30) |
| **Defined benefit obligation, end of year** | **578** | 578 |

An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, post employment medical and insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reporting date. Assumptions used in the actuarial valuation in order to determine the present value of the unfunded obligation are as follows:

| Assumptions used in actuarial valuation | 2018 | 2017 |
|---|---|---|
| Discount rate | **3.9%** | 3.9% |
| Consumer price index | **2.0%** | 2.0% |
| Compensation increase | **2.5%** | 2.5% |
| Health cost increases | **4.5%** | 4.5% |
| Dental cost increase | **4.5%** | 4.5% |
| Retirement age | **60** | 60 |

***Other long-term service benefits***

Other employee benefits that are expected to be settled wholly within 12 months after the end of the reporting period are presented as current liabilities. Other employee benefits that are not expected to be settled wholly within 12 months after the end of the reporting period are presented as non-current liabilities and calculated using the projected unit credit method and then discounted using yields available on high quality corporate bonds that have maturity dates approximating to the expected remaining period to settlement.

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

# 15. RELATED PARTY TRANSACTIONS

***Description of relationships between companies***

OPDC is related to the companies disclosed below as follows:

Corporation of the City of Orillia (“City”) is the ultimate parent and sole shareholder of Orillia Power Corporation (“OPC”).
OPC is the parent company and sole shareholder of both OPDC and Orillia Power Generation Corporation (“OPGC”).
OPGC – is an affiliate of OPDC under common control and parent company and sole shareholder of 2429106 Ontario Inc.

***IAS 24 disclosure exemptions***

The ultimate parent of the Company is the Corporation of the City of Orillia, which constitutes a local government. Consequently, OPDC is exempt from some of the general disclosure requirements of IAS 24 with relation to transactions with government-related parties and has applied the government-related disclosure requirements.

***Transactions with related parties***

OPDC provides electricity and other services to the City. OPDC also purchases services and pays property taxes and promissory note interest to the City. The Company has a shared services agreement with OPGC. Administrative staff costs are shared among the two companies as outlined in the agreement. OPDC has Affiliate Relationships Code and Standard Supply Service Code exemptions approved by the OEB to allow the shared services.

***Terms of repayment for due to and due from related parties***

The receivables from and payables to related parties are unsecured and have no formal specific terms of repayment.

***Key management personnel compensation***

Key management personnel are defined in IAS 24 as “those persons having authority and responsibility for planning, directing and controlling the activities of the entity, directly or indirectly, including any director (whether executive or otherwise) of that entity”. Key management personnel of the Company have been defined as members of its Board of Directors, officers and senior managers reporting directly to the President and Chief Executive Officer.

| Key management personnel compensation | 2018 | 2017 |
|---|---|---|
| | **$** | $ |
| Board of Directors | **36** | 122 |
| Officers and senior managers | **424** | 417 |
| | **460** | 539 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 15. RELATED PARTY TRANSACTIONS (continued)

A summary of related party transactions between the companies listed and described in the note above follows:

| Related party transactions | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **Financing activities with the City** | | |
| Finance costs paid to the City | **610** | 610 |
| **Operating activities with the City** | | |
| Power sold to the City | **2,616** | 2,735 |
| Other services sold to the City | **76** | 169 |
| Goods and services purchased from the City | **97** | 121 |
| Property taxes paid to the City | **74** | 74 |
| **Balances outstanding with the City** | | |
| Promissory note due to the City | **9,762** | 9,762 |
| Due from the City included in receivables | **319** | 304 |
| Due to the City included in payables | **8** | 24 |
| **Investing and financing activities with affiliates** | | |
| Dividends paid to OPC | **480** | 600 |
| **Operating activities with affiliates - sold to** | | |
| Goods and services sold to OPC | **2** | 2 |
| Goods and services sold to OPGC | **702** | 836 |
| Goods and services sold to 2429106 Ontario Inc. | **4** | 4 |
| **Operating activities with affiliates - purchased from** | | |
| Goods and services purchased from OPC | **38** | 125 |
| Goods and services purchased from OPGC | **347** | 319 |
| **Due from related parties** | | |
| Due from OPGC | **430** | 635 |
| Due from 2429106 Ontario Inc. | **5** | 11 |
| **Due to related parties** | | |
| Due to OPC | **36** | 122 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 16. INVENTORY

Cost of inventory is comprised of direct materials, which typically consists of distribution assets not deemed as major spares, unless purchased for specific capital projects in process or as spare units. Costs, after deducting rebates and discounts, are assigned to individual items of inventory based on weighted average cost. Decommissioned assets that are transferred to inventory are tested for impairment once they are removed from service and placed in inventory.

Inventory is recognized at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business less the estimated costs of completion and the estimated costs necessary to make the sale.

| Inventory | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Balance, beginning of year | **569** | 527 |
| Inventory purchased | **444** | 496 |
| Inventory used in: | | |
| Capital projects (capitalized) | **(255)** | (271) |
| Operations and maintenance (expensed) | **(122)** | (119) |
| Recoverable work | **(83)** | (62) |
| Other adjustments | **(1)** | (2) |
| **Balance, end of year** | **552** | 569 |

## 17. SHARE CAPITAL

***Nature and purpose of equity***

The reserves recorded in equity on the Company's Statement of Financial Position include "Share capital" and "Retained earnings". Share capital is used to record the issuance of equity. Retained earnings is used to record the Company's change in retained earnings from year to year.

***Share capital***

An unlimited number of common shares with no par value are authorized for issue. All shares are ranked equally with regards to the Company's residual assets and there was no change in share capital during the previous two years. OPDC does not have preference shares.

| Share capital | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Share capital | **8,236** | 8,236 |
| | **8,236** | 8,236 |
| | | |
| **Issued and fully paid:** | | |
| Number of common shares | **1,001** | 1,001 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 18. OPERATING EXPENSES

| Operating expenses | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **EXPENSES BY NATURE** | | |
| Board and staff costs | **2,697** | 2,790 |
| Operations and maintenance | **1,020** | 845 |
| Administration and general | **1,243** | 1,139 |
| Provision for credit loss on accounts receivable and unbilled revenue | **89** | 83 |
| Donations | **12** | 13 |
| | **5,061** | 4,870 |
| **EXPENSES BY FUNCTION** | | |
| Operations and maintenance | **2,527** | 2,288 |
| Billing and collection | **1,182** | 1,183 |
| Administration and general | **1,352** | 1,399 |
| | **5,061** | 4,870 |

## 19. FINANCE INCOME AND FINANCE COSTS

Finance income is comprised of interest income on funds invested such as cash and cash equivalents. Finance costs are comprised of interest payable on debt, post retirement benefits and impairment losses recognized on financial assets.

| Finance income and finance cost | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **FINANCE INCOME** | | |
| **Recognized in profit or loss:** | | |
| Interest income on bank deposits | **12** | 7 |
| | **12** | 7 |
| **FINANCE COST** | | |
| **Recognized in profit or loss:** | | |
| Interest on promissory notes payable to the City | **610** | 610 |
| Interest on third party debt | **186** | 176 |
| Interest on post retirement benefits | **22** | 22 |
| | **818** | 808 |
| **INTEREST PAID** | | |
| Finance costs | **818** | 808 |
| Less interest on post retirement benefits obligation | **22** | 22 |
| **Interest paid in cash** | **796** | 786 |

## NOTES TO THE FINANCIAL STATEMENTS

For the year ended December 31, 2018
(in thousands of Canadian dollars unless otherwise noted)

## 20. NON-CASH OR NON-OPERATING ADJUSTMENTS INCLUDED IN PROFIT

The following items are required to be added or subtracted from profit for the year in order to reconcile to net cash flows from operating activities on the Statement of Cash Flows:

| Other non-cash or non-operating items included in profit | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| **NON-REGULATORY ITEMS (NON-CASH OR NON-OPERATING) INCLUDED IN PROFIT** | | |
| Provision for PILs included in profit | **247** | 507 |
| Loss on disposal of PP&E | **59** | (93) |
| Amortization of deferred revenue | **(53)** | (45) |
| Post-retirement benefits | **8** | 8 |
| Finance income | **(12)** | (7) |
| Finance costs | **818** | 808 |
| | **1,067** | 1,178 |
| **REGULATORY ITEMS (NON-CASH)** | | |
| Net movement in regulatory deferral account balances including related deferred taxes | **374** | 356 |
| | **1,441** | 1,534 |

## 21. NET CHANGES IN NON-CASH WORKING CAPITAL

The following items related to year over year changes in working capital are required to be added or subtracted from profit for the year in order to reconcile to net cash flows from operating activities on the Statement of Cash Flows:

| Net changes in non-cash working capital | 2018 | 2017 |
|---|---|---|
| | $ | $ |
| Accounts receivable | **(1,169)** | 683 |
| Unbilled energy and distribution revenue | **86** | 799 |
| Inventories | **17** | (42) |
| Prepaid expenses | **30** | (11) |
| Due from related parties | **211** | 140 |
| Bank indebtedness to finance working capital requirements | **50** | (1,137) |
| Accounts payable and accrued liabilities | **(528)** | 275 |
| Payments in lieu of taxes payable | **169** | 59 |
| Customer security deposits | **653** | 121 |
| Due to related parties | **(86)** | (32) |
| | **(567)** | 855 |

## 22. COMMITMENTS AND CONTINGENCIES

***IESO prudential security commitments***

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 if the Company fails to make a payment required by default notice issued by the IESO. As at December 31, 2018, OPDC has provided prudential support to the IESO in the form of an irrevocable, automatically renewing bank letter of credit in the amount of $2,035 (December 31, 2017 - $2,035).

***Capital expenditure commitments***

The Company has entered into certain material contractual commitments with respect to capital spending for the 2019 fiscal year including $1,890 related to the construction of a new substation and $459 to purchase a new 65-foot double bucket truck. Both commitments were approved by the Board as part of the 2019 budget process. The substation build is expected to improve OPDC's overall system reliability and is required as a result of both accelerated load growth experienced in Orillia's west end and the existing substation coming to the end of its useful life. The truck is replacing an existing high usage vehicle at the end of its useful life.

***Liability insurance***

OPDC belongs to the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"), a self-insurance plan designed to pool all member risks. Any losses experienced by MEARIE are shared amongst all of its members. As of the date of Board of Directors approval of these financial statements, the Company has not been made aware of any assessments for significant losses. OPDC has contracted for a maximum total of $30 million in event coverage with MEARIE and $10 million in excess liability coverage with a secondary provider.

## 23. STANDARDS, AMENDMENTS AND INTERPRETATIONS NOT YET EFFECTIVE

Certain pronouncements were issued by the IASB or the IFRS Interpretations Committee that are mandatory for accounting years beginning after January 1, 2019 or later. The Company has not yet determined the extent of the impact of the following new standards, interpretations and amendments, which have not been applied in these financial statements:

***IFRS 16 Leases ("IFRS 16")***

IFRS 16 supersedes IAS 17, Leases, IFRIC 4, Determining whether an Arrangement contains a Lease, SIC-15, Operating Leases – Incentives and SIC-27, Evaluating the Substance of Transactions Involving the Legal Form of a Lease. It eliminates the distinction between operating and finance leases from the perspective of the lessee.

All contracts that meet the definition of a lease will be recorded in the statement of financial position with a "right of use" asset and a corresponding liability. The asset is subsequently accounted for as property, plant and equipment or investment property and the liability is unwound using the interest rate inherent in the lease. The accounting requirements from the perspective of the lessor remains largely in line with previous IAS 17 requirements.

The effective date for IFRS 16 is January 1, 2019.

The Company is in the process of evaluating the impact of this interpretation.

***IFRIC 23 Uncertainty over Income Tax Treatments ("IFRIC 23")***

IFRIC 23 provides guidance on recognition and measurement of uncertain income tax treatments.

The effective date for IFRIC 23 is January 1, 2019.

The Company is in the process of evaluating the impact of this interpretation.

# VECC INTERROGATORY # 1

**Reference:**

Exhibit A/Tab 1/Schedule 1, page 4 (line 3) and page 8 (lines 8-9)
Attachment 5 (Share Purchase Agreement), Schedule 6.2
EB-2016-0276, Exhibit I, Tab 3, Schedule 2

**Interrogatory:**

a) Is the list of community events/programs that OPDC supported in 2017 and 2018 that targeted residential, GS<50 and GS>50 customers as well as students and the general public similar to that provided in EB-2016-0276, Exhibit I, Tab 3, Schedule 2? If not please provide an updated list reflecting the community events/programs supported in the past two years.

b) Will all of the community event/programs OPDC supported in 2017 and 2018 be covered by the types of community events that HON proposes to sponsor (per Schedule 6.2)? If not, which ones would not be included?

**Response:**

a) Correct. The list of community events/programs that OPDC supported in 2017 and 2018 that targeted residential, GS<50 and GS>50 customers as well as students and the general public is similar to that provided in EB-2016-0276, Exhibit I, Tab 3, Schedule 2.

b) Hydro One's planned events are outlined in Schedule 6.2 of the Agreement provided as Attachment 5 of the Application. The Orillia community will be eligible to fully participate in all of Hydro One's community events/programs.

# VECC INTERROGATORY # 2

**Reference:**
Exhibit A/Tab 1/Schedule 1, page 5 (lines 8-17) Attachment 5

**Interrogatory:**
a) Is the Share Purchase Agreement the same as that filed in EB-2016-0276.

b) If not, please provide a schedule indicating the changes made.

**Response:**
a) The Share Purchase Agreement dated August 15, 2016 filed in EB-2016-0276 was subsequently amended. Attachment 5 to the prefiled evidence in the current Application (starting at page 87) also provides the amending agreement dated September 26, 2018 which indicates the changes made to the Share Purchase Agreement.

b) See part a) above.

# VECC INTERROGATORY # 3

**Reference:**
Exhibit A/Tab 1/Schedule 1, pages 6-7

**Interrogatory:**

a) On pages 6-7 the Application outlines a number of approvals that are being requested for actions to be taken by either OPDC or Hydro One. Please provide a timeline that, starting with the closing date of the transaction, sets out when each of these actions is expected to occur.

**Response:**

| **Approvals listed in Exhibit A-1-1, p. 8** | **Timeline** |
|---|---|
| Applying for leave to acquire all shares | September 2018 |
| OEB approves transaction | September 2019 |
| Transaction closes | January 2020 |
| OPDC seeks rate rider approval | September 2019 |
| OPDC applying to dispose of its distribution system to Hydro One Inc. | September 2019 |
| Hydro One seeking approval to establish a new ESM deferral account | September 2019 |
| OPDC request to cancel distribution licence | September 2020 |
| Hydro One's distribution license amended to serve OPDC service territory | September 2020 |
| OEB transfer OPDC's rate order to Hydro One | September 2020 |
| Hydro One seeking approval to update Specific Service Charges | September 2020 |
| Upon completion of integration, HOI will transfer the electricity distribution business previously known as OPDC to Hydro One | September 2020 |

# VECC INTERROGATORY # 4

**Reference:**

Exhibit A/Tab 1/Schedule 1, page 8 (lines 5-7)
EB-2016-0276, Exhibit I, Tab 3, Schedule 3, part (b)

**Interrogatory:**

a) Is the response provided to EB-2016-0276, Exhibit I, Tab 3, Schedule 3, part (b) regarding future CDM programs still applicable? If not, please provide an updated response.

**Response:**

Yes, the response provided to EB-2016-0276, Exhibit I, Tab 3, Schedule 3, part (b) regarding future CDM programs remains applicable. There is no update to provide regarding CDM programs.

# VECC INTERROGATORY # 5

**Reference:**
Exhibit A/Tab 2/Schedule 1, page 18 (lines 21-28) and page 19 (lines 17-20)
EB-2016-0276, Exhibit I, Tab 3, Schedule 4

**Interrogatory:**

a) Are the responses provided to EB-2016-0276, Exhibit I, Tab 3, Schedule 3, parts (b) and (c) regarding LEAP funding also applicable for the years 2017 and 2018? If not, please provide a revised response.

**Response:**
OPDC's LEAP funds were fully utilized in 2017 and 2018, having been depleted in May and June, respectively. Funds were depleted later compared to 2015 and 2016 as customers applied for assistance later as a result of the 2017/2018 and 2018/2019 Disconnection Ban Period. Hydro One's LEAP funds (including top-ups provided by the Corporation) assisted all potentially-eligible and approved customers in 2017 and 2018.

# VECC INTERROGATORY # 6

**Reference:**

Exhibit A/Tab 1/Schedule 1, page 7 (lines 9-11)
Exhibit A/Tab 2/Schedule 1, page 21 (lines 17-25) and Page 22 (lines 6-7)
Exhibit A, Attachments 12-17
EB-2016-0276, Exhibit I, Tab 3, Schedule 5, parts (a) – (d)

**Interrogatory:**

a) Please provide copies of the 2018 financial statements for OPDC, Hydro One Inc. and Hydro One Networks Inc.

b) Please provide an updated response to EB-2016-0276, Exhibit I, Tab 3, Schedule 5, part (a) as of December 31, 2018 and reconcile the balances with those in OPDC 2018 financial statements (per the response to part (a)).

c) Are the responses to EB-2016-0276, Exhibit I, Tab 3, Schedule 5, parts (b) – (d) still applicable? If not, please provide revised responses.

d) At what point in time will Hydro One cease making separate additions to OPDC's regulatory accounts and what is the basis for choosing this point in time?

**Response:**

a) i) OPDC's 2018 Financial Statements are provided at Exhibit I, Tab 4, Schedule 4 Attachment 1.
ii) Hydro One Inc.'s 2018 Financial Statements are provided as Attachment 1 to this Exhibit.
iii) Hydro One Distribution's 2018 Financial Statements are provided at Exhibit I, Tab 2, Schedule 41 Attachment 1.

b) Attachment 2 to this Exhibit provides OPDC's Regulatory Account balances as of December 31, 2018. These are reconciled to the balances shown in *Note 4.3- Detail for regulatory deferral account balances* to OPDC's 2018 financial statements.

c) The responses to EB-2016-0276, Exhibit I, Tab 3, Schedule 5, parts (b) – (d) are still applicable. Hydro One intends to continue to make additional entries to all Group 1

Variance Account, as applicable, based on Hydro One's allocation methodology as reviewed by OEB Staff in March 2019. This methodology allocates total RSVA balances to any acquired LDCs based on post-integrated sales volumes. As mentioned, this method was reviewed by OEB Staff through their RPP Settlement Process and DVA Allocation Methodology audit that was completed recently in March 2019. The audit concluded the proposed allocation method is reasonable.

d) Hydro One intends to cease the recording of separate additions to the OPDC legacy regulatory Group 1 accounts when OPDC is rebased. At that time there will be no further separation of OPDC for regulatory account purposes. Hydro One is able to maintain a line of sight to former OPDC customers for the purpose of applying Rate Riders to refund/recover OEB-approved regulatory account balances recorded prior to rebasing.

Group 2 accounts would be assessed individually and will be be reviewed by the Board in a future rate making proceeding.

# NOTICE TO READER

Please be advised that Hydro One Inc. (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 31(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, Risk Management and Risk Factors, Summary of Fourth Quarter Results of Operations, 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.

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 Inc. (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 | Christopher Lopez |
| Acting President and Chief Executive Officer | Acting Chief Financial Officer |

To the Shareholder and Board of Directors of Hydro One Inc.

*Opinion on the Amended Consolidated Financial Statements*

We have audited the accompanying amended consolidated balance sheet of Hydro One Inc. (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

To the Shareholder and Board of Directors of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., 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 Inc. 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, 2018 and 2017

| Year ended December 31 *(millions of Canadian dollars, except per share amounts)* | 2018 | 2017 |
|---|---|---|
| **Revenues** | | |
| Distribution (includes $280 related party revenues; 2017 - $284) *(Note 26)* | 4,422 | 4,366 |
| Transmission (includes $1,620 related party revenues; 2017 - $1,526) *(Note 26)* | 1,688 | 1,581 |
| | 6,110 | 5,947 |
| **Costs** | | |
| Purchased power (includes $1,648 related party costs; 2017 - $1,594) *(Note 26)* | 2,899 | 2,875 |
| Operation, maintenance and administration *(Note 26)* | 1,055 | 1,014 |
| Depreciation, amortization and asset removal costs *(Note 5)* | 830 | 810 |
| | 4,784 | 4,699 |
| **Income before financing charges and income taxes** | **1,326** | **1,248** |
| Financing charges *(Note 6)* | 418 | 411 |
| **Income before income taxes** | **908** | **837** |
| Income taxes *(Note 7)* | 933 | 120 |
| **Net income (loss)** | **(25)** | **717** |
| Other comprehensive income | 2 | — |
| **Comprehensive income (loss)** | **(23)** | **717** |
| **Net income (loss) attributable to:** | | |
| Noncontrolling interest *(Note 25)* | 6 | 6 |
| Preferred shareholder | 9 | — |
| Common shareholder | (40) | 711 |
| | **(25)** | **717** |
| **Comprehensive income (loss) attributable to:** | | |
| Noncontrolling interest *(Note 25)* | 6 | 6 |
| Preferred shareholder | 9 | — |
| Common shareholder | (38) | 711 |
| | **(23)** | **717** |
| **Earnings per common share** *(Note 23)* | | |
| Basic | ($281) | $4,999 |
| Diluted | ($281) | $4,999 |
| **Dividends per common share declared** *(Note 22)* | $42 | $105 |

*See accompanying notes to Amended Consolidated Financial Statements.*

## HYDRO ONE INC.
## AMENDED CONSOLIDATED BALANCE SHEETS
### At December 31, 2018 and 2017

| December 31 *(millions of Canadian dollars)* | 2018 | 2017 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | 492 | — |
| Accounts receivable *(Note 8)* | 625 | 635 |
| Due from related parties *(Note 26)* | 324 | 302 |
| Other current assets *(Note 9)* | 99 | 104 |
| | 1,540 | 1,041 |
| Property, plant and equipment *(Note 10)* | 20,605 | 19,871 |
| Other long-term assets: | | |
| Regulatory assets *(Note 12)* | 1,721 | 3,049 |
| Deferred income tax assets *(Note 7)* | 964 | 954 |
| Intangible assets *(Note 11)* | 409 | 369 |
| Goodwill | 325 | 325 |
| Other assets | 5 | 5 |
| | 3,424 | 4,702 |
| **Total assets** | **25,569** | **25,614** |
| **Liabilities** | | |
| Current liabilities: | | |
| Bank indebtedness | — | 3 |
| Short-term notes payable *(Note 15)* | 1,252 | 926 |
| Long-term debt payable within one year *(Notes 15, 16)* | 731 | 752 |
| Accounts payable and other current liabilities *(Note 13)* | 936 | 892 |
| Due to related parties *(Note 26)* | 129 | 206 |
| | 3,048 | 2,779 |
| Long-term liabilities: | | |
| Long-term debt (includes $845 measured at fair value; 2017 – $541) *(Notes 15, 16)* | 9,978 | 9,315 |
| Regulatory liabilities *(Note 12)* | 326 | 128 |
| Deferred income tax liabilities *(Note 7)* | 55 | 70 |
| Other long-term liabilities *(Note 14)* | 2,164 | 2,734 |
| | 12,523 | 12,247 |
| **Total liabilities** | **15,571** | **15,026** |
| *Contingencies and Commitments* *(Notes 28, 29)* | | |
| *Subsequent Events* *(Notes 12, 31)* | | |
| Preferred shares *(Note 21)* | 486 | 486 |
| Noncontrolling interest subject to redemption *(Note 25)* | 21 | 22 |
| **Equity** | | |
| Common shares *(Note 21)* | 4,312 | 4,856 |
| Retained earnings | 5,137 | 5,183 |
| Accumulated other comprehensive loss | (7) | (9) |
| Hydro One shareholder's equity | 9,442 | 10,030 |
| Noncontrolling interest *(Note 25)* | 49 | 50 |
| **Total equity** | **9,491** | **10,080** |
| | **25,569** | **25,614** |

*See accompanying notes to Amended Consolidated Financial Statements.*

On behalf of the Board of Directors:

Tom Woods
Chair

William Sheffield
Chair, Audit Committee

# HYDRO ONE INC.
## AMENDED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
**For the years ended December 31, 2018 and 2017**

| Year ended December 31, 2018 *(millions of Canadian dollars)* | Common Shares | Retained Earnings | Accumulated Other Comprehensive Loss | Hydro One Shareholder's Equity | Non-controlling Interest *(Note 25)* | Total Equity |
|---|---|---|---|---|---|---|
| January 1, 2018 | 4,856 | 5,183 | (9) | 10,030 | 50 | 10,080 |
| Net income (loss) | — | (31) | — | (31) | 4 | (27) |
| Other comprehensive income | — | — | 2 | 2 | — | 2 |
| Distributions to noncontrolling interest | — | — | — | — | (5) | (5) |
| Dividends on preferred shares | — | (9) | — | (9) | — | (9) |
| Dividends on common shares | — | (6) | — | (6) | — | (6) |
| Return of stated capital *(Note 21)* | (544) | — | — | (544) | — | (544) |
| **December 31, 2018** | **4,312** | **5,137** | **(7)** | **9,442** | **49** | **9,491** |

| Year ended December 31, 2017 *(millions of Canadian dollars)* | Common Shares | Retained Earnings | Accumulated Other Comprehensive Loss | Hydro One Shareholder's Equity | Non-controlling Interest *(Note 25)* | Total Equity |
|---|---|---|---|---|---|---|
| January 1, 2017 | 5,391 | 4,487 | (9) | 9,869 | 50 | 9,919 |
| Net income | — | 711 | — | 711 | 4 | 715 |
| Other comprehensive income | — | — | — | — | — | — |
| Distributions to noncontrolling interest | — | — | — | — | (4) | (4) |
| Dividends on common shares | — | (15) | — | (15) | — | (15) |
| Return of stated capital *(Note 21)* | (535) | — | — | (535) | — | (535) |
| **December 31, 2017** | **4,856** | **5,183** | **(9)** | **10,030** | **50** | **10,080** |

*See accompanying notes to Amended Consolidated Financial Statements.*

## AMENDED CONSOLIDATED STATEMENTS OF CASH FLOWS

**For the years ended December 31, 2018 and 2017**

| Year ended December 31 *(millions of Canadian dollars)* | 2018 | 2017 |
|---|---|---|
| **Operating activities** | | |
| Net income (loss) | (25) | 717 |
| Environmental expenditures | (22) | (24) |
| Adjustments for non-cash items: | | |
| Depreciation and amortization *(Note 5)* | 740 | 720 |
| Regulatory assets and liabilities | 35 | 112 |
| Deferred income taxes | 909 | 96 |
| Other | 17 | 10 |
| Changes in non-cash balances related to operations *(Note 27)* | (50) | 63 |
| **Net cash from operating activities** | **1,604** | **1,694** |
| | | |
| **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) |
| Promissory note issued *(Note 26)* | — | 486 |
| Promissory note repaid *(Note 26)* | — | (486) |
| Return of stated capital | (544) | (535) |
| Preferred shares issued | — | 486 |
| Dividends paid | (15) | (15) |
| Distributions paid to noncontrolling interest | (8) | (6) |
| Change in bank indebtedness | (3) | 3 |
| Other | (6) | — |
| **Net cash from (used in) financing activities** | **397** | **(212)** |
| | | |
| **Investing activities** | | |
| Capital expenditures *(Note 27)* | | |
| Property, plant and equipment | (1,411) | (1,456) |
| Intangible assets | (120) | (80) |
| Capital contributions received *(Note 27)* | 7 | 9 |
| Other | 15 | (3) |
| **Net cash used in investing activities** | **(1,509)** | **(1,530)** |
| | | |
| **Net change in cash and cash equivalents** | 492 | (48) |
| Cash and cash equivalents, beginning of year | — | 48 |
| **Cash and cash equivalents, end of year** | **492** | **—** |

*See accompanying notes to Amended Consolidated Financial Statements.*

## 1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly-owned by Hydro One Limited. 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 its 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 its 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 31(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. Certain comparative figures have been reclassified to conform to the presentation of these Consolidated Financial Statements.

**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 the shareholder 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. As at December 31, 2018 and 2017, no asset impairment had been recorded.

**Costs of Arranging Debt Financing**

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt 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 16 - 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.

<u>Defined Benefit Pension</u>

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 Hydro One Limited 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited 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 | 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 $24 million of 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. |
| 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 COMBINATIONS

### 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 | 647 | 634 |
| Amortization of intangible assets | 71 | 62 |
| Amortization of regulatory assets | 22 | 24 |
| Depreciation and amortization | 740 | 720 |
| Asset removal costs | 90 | 90 |
| | 830 | 810 |

## 6. FINANCING CHARGES

| Year ended December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Interest on long-term debt | 447 | 450 |
| Interest on short-term notes | 14 | 6 |
| Other | 17 | 12 |
| Less: Interest capitalized on construction and development in progress | (53) | (56) |
| Interest earned on cash and cash equivalents | (7) | (1) |
| | 418 | 411 |

## 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 | 908 | 837 |
| Income taxes at statutory rate of 26.5% (2017 - 26.5%) | 241 | 222 |
| 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) | 1 |
| Net temporary differences | (128) | (105) |
| Net permanent differences | 3 | 3 |
| Write-off of unregulated deferred income tax asset *(Notes 12, 31)* | 885 | — |
| Non-recurring tax recovery relating to deferred tax asset sharing[1] *(Notes 12, 31)* | (68) | — |
| Total income taxes | 933 | 120 |
| Effective income tax rate | 102.8% | 14.3% |

[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 | 24 | 24 |
| Deferred income taxes | 909 | 96 |
| Total income taxes | 933 | 120 |

### 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 | 523 | 558 |
| Non-depreciable capital property | 271 | 271 |
| Non-capital losses | 263 | 240 |
| 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 | 5 | 109 |
| Other | 24 | 22 |
| | 1,499 | 1,758 |
| Less: valuation allowance | (366) | (364) |
| Total deferred income tax assets | 1,133 | 1,394 |
| | | |
| **Deferred income tax liabilities** | | |
| Capital cost allowance in excess of depreciation and amortization | 9 | 74 |
| Regulatory amounts that are not recognized for tax purposes | 188 | 410 |
| Goodwill | 10 | 10 |
| Other | 17 | 16 |
| Total deferred income tax liabilities | 224 | 510 |
| | | |
| Net deferred income tax assets | 909 | 884 |

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 | 964 | 954 |
| Deferred income tax liabilities | (55) | (70) |
| Net deferred income tax assets | 909 | 884 |

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 | 220 | 221 |
| 2036 | 549 | 558 |
| 2037 | 121 | 123 |
| 2038 | 99 | — |
| Total losses | 991 | 904 |

## 8. ACCOUNTS RECEIVABLE

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Accounts receivable – billed | 289 | 297 |
| Accounts receivable – unbilled | 357 | 367 |
| Accounts receivable, gross | 646 | 664 |
| Allowance for doubtful accounts | (21) | (29) |
| Accounts receivable, net | 625 | 635 |

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 | 37 | 40 |
| Materials and supplies | 20 | 18 |
| | 99 | 104 |

## 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 | 1,121 | 804 | 33 | 350 |
| Administration and service | 1,548 | 893 | 58 | 713 |
| Easements | 647 | 75 | — | 572 |
| | 30,455 | 10,782 | 932 | 20,605 |

| 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 | 1,088 | 742 | 22 | 368 |
| Administration and service | 1,561 | 857 | 46 | 750 |
| Easements | 638 | 70 | — | 568 |
| | 29,009 | 10,344 | 1,206 | 19,871 |

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 | 59 | 409 |
| Other | 5 | 5 | — | — |
| | 795 | 445 | 59 | 409 |

| 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 Limited 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 prudency 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 - $7 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 | 171 | 173 |
| Accrued liabilities | 578 | 563 |
| Accrued interest | 96 | 99 |
| Regulatory liabilities *(Note 12)* | 91 | 57 |
| | 936 | 892 |

## 14. OTHER LONG-TERM LIABILITIES

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Post-retirement and post-employment benefit liability *(Note 18)* | 1,406 | 1,507 |
| Pension benefit liability *(Note 18)* | 547 | 981 |
| Environmental liabilities *(Note 19)* | 139 | 168 |
| Due to related parties *(Note 26)* | 41 | 39 |
| Long-term accounts payable | 11 | 13 |
| Asset retirement obligations *(Note 20)* | 10 | 9 |
| Other liabilities | 10 | 17 |
| | 2,164 | 2,734 |

## 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 its 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 the Company's committed revolving credit facilities totalling $2.3 billion. At December 31, 2018, no amounts have been drawn on the Operating Credit Facilities.

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.

### 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 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 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'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 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. 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, bank indebtedness, 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 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's fair value hedge exposure was approximately 8% (2017 – 6%) of its total long-term debt. At December 31, 2018, Hydro One 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.

**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 | 492 | 492 | 492 | — | — |
| | 492 | 492 | 492 | — | — |
| **Liabilities:** | | | | | |
| Bank indebtedness | — | — | — | — | — |
| Short-term notes payable | 1,252 | 1,252 | 1,252 | — | — |
| Long-term debt, including current portion | 10,709 | 11,665 | — | 11,665 | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 5 | 5 | — | 5 | — |
| | 11,966 | 12,922 | 1,252 | 11,670 | — |

| December 31, 2017 *(millions of dollars)* | Carrying Value | Fair Value | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|---|
| **Liabilities:** | | | | | |
| Bank indebtedness | 3 | 3 | 3 | — | — |
| Short-term notes payable | 926 | 926 | 926 | — | — |
| Long-term debt, including current portion | 10,067 | 11,568 | — | 11,568 | — |
| Derivative instruments | | | | | |
| Fair value hedges – interest-rate swaps | 9 | 9 | — | 9 | — |
| | 11,005 | 12,506 | 929 | 11,577 | — |

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.

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 or material foreign exchange 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.

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.

## 17. 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 |
| Bank indebtedness | — | 3 |
| Less: cash and cash equivalents | (492) | — |
| | 1,491 | 1,681 |
| Long-term debt | 9,978 | 9,315 |
| Preferred shares | 486 | 486 |
| Common shares | 4,312 | 4,856 |
| Retained earnings | 5,137 | 5,183 |
| **Total capital** | 21,404 | 21,521 |

Hydro One 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.

## 18. 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:

| | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| Year ended December 31 *(millions of dollars)* | 2018 | 2017 | 2018 | 2017 |
| **Change in projected benefit obligation** | | | | |
| Projected benefit obligation, beginning of year | 8,258 | 7,774 | 1,552 | 1,676 |
| Current service cost | 176 | 147 | 49 | 48 |
| Employee contributions | 52 | 49 | — | — |
| Interest cost | 282 | 304 | 54 | 67 |
| Benefits paid | (362) | (368) | (49) | (44) |
| Net actuarial loss (gain) | (654) | 352 | (156) | (195) |
| Recognition of prior service | — | — | 3 | — |
| Projected benefit obligation, end of year | 7,752 | 8,258 | 1,453 | 1,552 |
| **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 | 1,453 | 1,552 |

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

| | Pension Benefits | | Post-Retirement and Post-Employment Benefits | |
|---|---|---|---|---|
| December 31 *(millions of dollars)* | 2018 | 2017 | 2018 | 2017 |
| Other assets[1] | 3 | 1 | — | — |
| Accrued liabilities | — | — | 54 | 52 |
| Pension benefit liability | 547 | 981 | — | — |
| Post-retirement and post-employment benefit liability[2] | — | — | 1,406 | 1,507 |
| Net unfunded status | 544 | 980 | 1,460 | 1,559 |

[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] | 31 | 37 |

[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 $74 million (2017 - $85 million) were attributed to labour, of which $31 million (2017 - $37 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 | 49 | 48 |
| Interest cost | 53 | 67 |
| Amortization of actuarial losses | 15 | 16 |
| Recognition of prior service | 3 | — |
| Net periodic benefit costs | 120 | 131 |
| Charged to results of operations | 50 | 58 |

**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 | 228 | 247 |
| Effect of a 1% decrease in health care cost trends | (173) | (188) |

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 | 28 |
| 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 | | | | December 31, 2017 | | | |
|---|---|---|---|---|---|---|---|
| Life expectancy at 65 for a member currently at | | | | 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 | 57 |
| 2021 | 352 | 59 |
| 2022 | 360 | 60 |
| 2023 | 367 | 61 |
| 2024 through to 2028 | 1,915 | 324 |
| Total estimated future benefit payments through to 2028 | 3,672 | 617 |

### 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 | (155) | (195) |
| Amortization of actuarial losses | (15) | (16) |
| Amortization of prior service cost | (3) | — |
| Amounts not subject to regulatory treatment | 7 | 4 |
| | (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 of Ontario (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 16 - 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.

## 19. 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 PCBs 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).

## 20. 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.

## 21. SHARE CAPITAL

**Common Shares**

The Company is authorized to issue an unlimited number of common shares. At December 31, 2018, the Company had 142,239 (2017 - 142,239) common shares issued and outstanding.

In 2018, a return of stated capital in the amount of $544 million (2017 - $535 million) was paid.

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.

**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 Class A preferred shares and Class B preferred shares. At December 31, 2018 and 2017, the Company had 485,870 Class B preferred shares and no Class A preferred shares issued and outstanding.

Class A Preferred Shares

On November 2, 2015, a special resolution of Hydro One Limited (as sole shareholder of Hydro One) was made to amend the articles of Hydro One to delete the share ownership restrictions and to amend the Hydro One preferred share terms to provide for basic redeemable preferred shares. When issued, the Class A preferred shares will be redeemable at the option of the Company. The holders of the Class A preferred shares will be entitled to receive, if and when declared by the Hydro One Board of Directors, non-cumulative preferred share dividends at a rate per year to be determined by the Hydro One Board of Directors. The holders of the Class A preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class A preferred shares will be entitled to receive, before any distributions to the holders of common shares and any other shares ranking junior to the Class A preferred shares, an amount equal to the amount paid for the Class A preferred shares together with all dividends declared and unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

Class B Preferred Shares

On November 10, 2017, a special resolution of Hydro One Limited was made to amend the articles of Hydro One to create an unlimited number of Class B preferred shares. The holders of the Class B preferred shares are 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 average 3-month Canadian dollar bankers' acceptance rate and 0.25% as reset quarterly. The holders of the Class B preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class B preferred shares will be entitled to receive, before any distributions to the holders of the Class A preferred shares, the common shares and any other shares ranking junior to the Class B preferred shares, an amount equal to the amount paid for the Class B preferred shares together with all dividends unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

The Class B preferred shares have a redemption feature that is outside the control of the Company because the holders can exercise their right to redeem the Class B preferred shares at any time without approval of the Company's Board of Directors. The Class B preferred shares are classified on the Consolidated Balance Sheet as temporary equity because this redemption feature is outside the control of the Company.

On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, for proceeds of $486 million.

## 22. DIVIDENDS

In 2018, preferred share dividends in the amount of $9 million (2017 - $nil) and common share dividends in the amount of $6 million (2017 - $15 million) were declared.

## 23. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income (loss) attributable to common shareholder of Hydro One by the weighted-average number of common shares outstanding. The weighted-average number of common shares outstanding at December 31, 2018 was 142,239 (2017 – 142,239). There were no dilutive securities during 2018 or 2017.

## 24. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One in current and future periods.

**Share Grant Plans**

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (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). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,952,212 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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 Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,367,158 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The fair value of the Hydro One Limited 2015 share grants of $111 million was estimated based on the grant date Hydro One Limited 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, 473,222 common shares of Hydro One Limited were issued under the Share Grant Plans (2017 - 369,266) to eligible employees of Hydro One. 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 | 4,737,783 | $20.50 |
| Vested and issued[1] | (473,222) | — |
| Forfeited | (105,122) | $20.50 |
| Share grants outstanding - ending | 4,159,439 | $20.50 |

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One made payments to Hydro One Limited for the common shares issued.

| Year ended December 31, 2017 | Share Grants *(number of common shares)* | Weighted-Average Price |
|---|---|---|
| Share grants outstanding - beginning | 5,239,678 | $20.50 |
| Vested and issued[1] | (369,266) | — |
| Forfeited | (132,629) | $20.50 |
| Share grants outstanding - ending | 4,737,783 | $20.50 |

[1] In 2017, Hydro One Limited issued from treasury common shares to eligible Hydro One employees in accordance with provisions of the PWU Share Grant Plan. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One made payments to Hydro One Limited for the common shares issued.

### 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 Limited'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 Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited'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 Hydro One Limited 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 | 63,760 | — |
| Granted | 40,281 | 64,828 |
| Paid | — | (1,068) |
| DSUs outstanding - ending | 104,041 | 63,760 |

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 Hydro One Limited 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 Hydro One Limited 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 Limited 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 Limited. 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 Limited. 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 Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited 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 Limited.

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 | 425,120 | 228,890 | 388,140 | 252,440 |
| Granted | 438,470 | 300,090 | 338,480 | 239,280 |
| Vested and issued[1] | (123) | (609) | (104,881) | (14,079) |
| Forfeited | (30,967) | (103,251) | (30,649) | (89,501) |
| Settled | (238,030) | — | (158,310) | — |
| Units outstanding - ending | 594,470 | 425,120 | 432,780 | 388,140 |

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One employees in accordance with provisions of the LTIP. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One made payments to Hydro One Limited for the common shares issued.

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.

At December 31, 2018, $20 million (2017 - $9 million) payable to Hydro One Limited relating to PSU and RSU awards was included in due to related parties on the Consolidated Balance Sheets.

Stock Options

Hydro One Limited is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, Hydro One Limited 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 Limited common share price on the date of the grant.
2 Based on dividend and Hydro One Limited common share price on the date of the grant.
3 Based on average daily volatility of Hydro One Limited's 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.

At December 31, 2018, $1 million (2017 - $nil) payable to Hydro One Limited relating to Stock Options awards was included in due to related parties on the Consolidated Balance Sheets.

## 25. 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 |

## 26. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited 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), the OEB, Hydro One Telecom, and 2587264 Ontario Inc. are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited.

Year ended December 31 *(millions of dollars)*

| Related Party | Transaction | 2018 | 2017 |
|---|---|---|---|
| **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 | 8 | 7 |
| | 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 |
| **Hydro One Limited** | Return of stated capital | 544 | 535 |
| | Dividends paid | 6 | 15 |
| | Stock-based compensation costs | 28 | 23 |
| | Cost recovery for services provided | 15 | 6 |
| **Hydro One Telecom** | Services received – costs expensed | 23 | 24 |
| | Revenues for services provided | 3 | 3 |
| **2587264 Ontario Inc.** | Promissory note issued and repaid[1] | — | 486 |
| | Preferred shares issued[2] | — | 486 |
| | Dividends paid | 9 | — |

[1] On October 17, 2017, Hydro One issued a promissory note to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, totalling $486 million. On November 20, 2017, Hydro One repaid the $486 million promissory note to 2587264 Ontario Inc., as well as interest totalling $1 million.

[2] On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc. for proceeds of $486 million. See Note 21 for details of the Class B preferred shares.

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.

## 27. 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 | 13 | 191 |
| Due from related parties | (22) | (78) |
| Other assets | 3 | 3 |
| Accounts payable | (2) | 7 |
| Accrued liabilities | 18 | (89) |
| Due to related parties | (78) | (49) |
| Accrued interest | (3) | (6) |
| Long-term accounts payable and other liabilities | (5) | (2) |
| Post-retirement and post-employment benefit liability | 26 | 86 |
| | (50) | 63 |

### 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 | (1,441) | (121) | (1,562) |
| Reconciling items | 30 | 1 | 31 |
| Cash outflow for capital expenditures | (1,411) | (120) | (1,531) |

| Year ended December 31, 2017 *(millions of dollars)* | Property, Plant and Equipment | Intangible Assets | Total |
|---|---|---|---|
| Capital investments | (1,482) | (74) | (1,556) |
| Reconciling items | 26 | (6) | 20 |
| Cash outflow for capital expenditures | (1,456) | (80) | (1,536) |

### 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 | 458 | 452 |
| Income taxes paid | 15 | 11 |

## 28. 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, 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.

### 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.

## 29. 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 | 6 | 10 | 4 | 1 | 1 | 3 |

### 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 $10 million (2017 - $10 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 | — | — | — | 2,300 | — | — |
| Letters of credit[1] | 174 | — | — | — | — | — |
| Guarantees[2] | 325 | — | — | — | — | — |

[1] Letters of credit consist of letters of credit totalling $155 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 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's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One 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'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.

## 30. 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.

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 | 1,688 | 4,422 | — | 6,110 |
| Purchased power | — | 2,899 | — | 2,899 |
| Operation, maintenance and administration | 424 | 608 | 23 | 1,055 |
| Depreciation and amortization | 435 | 395 | — | 830 |
| **Income (loss) before financing charges and income taxes** | 829 | 520 | (23) | 1,326 |
| **Capital investments** | 985 | 577 | — | 1,562 |

| Year ended December 31, 2017 *(millions of dollars)* | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| Revenues | 1,581 | 4,366 | — | 5,947 |
| Purchased power | — | 2,875 | — | 2,875 |
| Operation, maintenance and administration | 391 | 599 | 24 | 1,014 |
| Depreciation and amortization | 420 | 390 | — | 810 |
| **Income (loss) before financing charges and income taxes** | 770 | 502 | (24) | 1,248 |
| **Capital investments** | 968 | 588 | — | 1,556 |

**Total Assets by Segment:**

| December 31 *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Transmission | 13,877 | 13,523 |
| Distribution | 9,277 | 9,229 |
| Other | 2,415 | 2,862 |
| **Total assets** | 25,569 | 25,614 |

**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 costs, as the case may be, are earned, held or incurred in Canada.

## 31. SUBSEQUENT EVENTS

### (A) Preferred Shares, Dividends and Return of Stated Capital

On January 24, 2019, the Company redeemed its preferred shares totalling $486 million, and paid $2 million of preferred share dividends.

On February 20, 2019, common share dividends of $1 million were declared. On the same date, a return of stated capital of $138 million was approved.

### (B) LTIP

On January 29, 2019, Hydro One Limited 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.

# Orillia Power Distribution Corporation

| Note 4.3 Detail for regulatory deferral account balances | Account #'s | 31-Dec-18 | 31-Dec-17 |
|---|---|---|---|
| Regulatory deferral account debit balances | | | |
| Low Voltage | 1550 | 1,311,695 | 1,392,029 |
| Stranded Meter Capital | 1555 | 171,836 | 205,929 |
| Lost Revenue Variance | 1568 | 401,704 | 241,822 |
| Network services - transmission | 1584 | | 5,197 |
| Connection services - transmission | 1586 | | 18,854 |
| Global adjustment | 1589 | | 24,531 |
| Residual balance disposition / recoveries | 1595 | 64,654 | 54,146 |
| Other Regulatory Assets | 1508 | 50,532 | 37,579 |
| Regulatory deferral account debit balances - total | | **2,000,421** | **1,980,087** |
| | | | |
| Regulatory deferral account credit balances | | | |
| Retail costs | 1518 / 1548 | 70,047 | 69,276 |
| Smart Meter Entity Variance | 1551 | 14,618 | 8,667 |
| IFRS-CGAAP Transitional PP&E Amounts | 1575 | 13,563 | 13,563 |
| Change in PP&E useful lives estimates | 1576 | 2,593,390 | 1,900,711 |
| Wholesale market services | 1580 | 861,205 | 1,072,629 |
| Network services - transmission | 1584 | 61,954 | |
| Connection services - transmission | 1586 | 94,035 | |
| Power | 1588 | 364,531 | 219,464 |
| Global adjustment | 1589 | 50,757 | |
| Regulatory deferral account credit balances - total | | **4,124,100** | **3,284,310** |

| Note 4.1 Regulatory deferral account balances net of deferred taxes | | |
|---|---|---|
| Regulatory deferral account debit balances | | |
| **Regulatory deferral account debit balances** | **2,000,421** | **1,980,087** |
| **Less deferred tax impact** | (530,000) | (525,000) |
| **Regulatory deferral account debit balances net of deferred taxes** | **1,470,421** | **1,455,087** |
| | | |
| Regulatory deferral account credit balances | | |
| **Regulatory deferral account credit balances** | **4,124,100** | **3,284,310** |
| **Less deferred tax impact** | (1,093,000) | (870,000) |
| **Regulatory deferral account credit balances net of deferred taxes** | **3,031,100** | **2,414,310** |

# VECC INTERROGATORY # 7

**Reference:**

Exhibit A/Tab 2/Schedule 1, page 2, Table 1
EB-2016-0276, Exhibit A/Tab 2/Schedule 1, page 2, Table 1

**Interrogatory:**

a) Please explain the material increase in forecast OM&A costs under the Status Quo forecast as between the EB-2016-0276 Application and the current Application (i.e., ten-year total increases from $52.6 M to $60.7 M).

b) More specifically, please explain the increase in forecast OM&A costs for year 1 under the Status Quo from $4.8 M to $5.5 M.

c) Given the response to part (a), please explain why the forecast OM&A under the Hydro One forecast has decreased slightly as between the EB-2016-0276 Application and the current Application (i.e., ten-year total decreases from $20.7 M to $20.6 M).

d) In the current Application, please provide the reasons for the significant increase in forecast capital spending in year 9 of the Status Quo forecast and why there is no similar increase in the Hydro One forecast.

**Response:**

a) Please see Exhibit I, Tab 2, Schedule 3b).

b) Please see Exhibit I, Tab 2, Schedule 3b).

c) Please see Exhibit I, Tab 2, Schedule 3c).

d) See Exhibit I, Tab1, Schedule 3a).

# VECC INTERROGATORY # 8

**Reference:**
Exhibit A/Tab 2/Schedule 1, page 2, Table 1
Exhibit A/Tab 2/Schedule 1, page 13, (lines 3-13 and Table 5)
EB-2016-0276, Exhibit I, Tab 3, Schedule 10 Attachment 18

**Interrogatory:**

a) What portion of OPDC's actual 2017 OM&A costs ($4.87 M) is labour-related?

b) What were the main non-labour contributors to OPDC's actual 2017 OM&A costs?

c) What portion of the OM&A reduction shown in Table 1 as between the Status Quo and the Hydro One forecast is due to the proposed elimination of 25 local positions (per page 13)?

d) What are the sources for the balance of the assumed OM&A savings in the Hydro One forecast versus the Status Quo forecast? In responding, please be specific as to the non-labour sources for these savings.

e) The response to EB-2016-0276, Exhibit I, Tab 3, Schedule 10, part c) indicated that in the previous Application the Hydro One forecast OM&A included an evaluation of the incremental administrative and support services costs as a result of absorbing OPDC. Was a similar evaluation performed for the current Application? If yes, please provide. If not, why not?

f) Does the Hydro One Forecast OM&A in Table 1 include any allowance for incremental costs associated with administration or support services (e.g. back-office services, customer service, finance, human resources, distribution system planning& design, executive & governance, etc.)? If yes, for what services were incremental costs included, what costs (i.e., dollars) were included in each year for each service and how were they determined? If not, why not?

**Response:**

a) OPDC's labour-related OM&A costs were $2.67 M in 2017.

b) The main contributors to OPDC's non-labour OM&A costs in 2017 were third party contractor costs, professional & outside services fees, regulatory costs, insurance and property taxes, and material, vehicle, equipment & supply expenses. Other costs, including the operations and maintenance of the service centre building, loss provision for accounts receivable and donations, account for the remaining non-labour OM&A costs.

c) The elimination of the 25 former OPDC positions is only one element of the overall shift to Hydro One's integrated operation of the former OPDC service territory. The staff associated with these OPDC positions will be absorbed into Hydro One's operations.

The Hydro One forecast assessed the total incremental dollar cost to serve the new territory. While labour costs are captured within the overall incremental cost envelope, the forecasting approach did not utilize a forecast of head count or FTE metrics. In other words, incremental labour costs are captured, but not in a manner readily separated from the total.

Exhibit I, Tab 1, Schedule 3 part b) provides combined labour and non-labour OM&A savings by business area.

d) See part c) above.

e) The Hydro One Forecast considered all incremental OM&A costs which by definition included applicable incremental administration or support services costs (e.g. customer care). Customer care (e.g. billing, call center) represents a significant incremental cost that has been provided for in the Hydro One Forecast. Exhibit I, Tab 1, Schedule 19 part a) provides the forecast approach and annual dollar amounts forecast. Overhead costs, such as finance and human resources, are expected to experience no incremental costs.

For a discussion of the Hydro One Forecast provided in the current Application, please see Exhibit I, Tab 1, Schedule 19 part a).

f) See part e) above.

# VECC INTERROGATORY # 9

**Reference:**
Exhibit A/T5/S1, page 2 (lines 7-13)

**Interrogatory:**
Preamble: The Supplemental Evidence states:

"In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of OPDC, and commits to tracking the actual incremental OM&A and capital costs to serve OPDC customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve OPDC customers with that forecast in this application. The actual incremental OM&A and capital costs to serve OPDC customers will be reflected in Hydro One's revenue requirement upon rebasing of rates at the end of the ten year deferral period."

a) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast OM&A (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (EB-2017-0049, DRO Exhibit 3.1, Tab I3-TB Data).

b) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast Capital Expenditures (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (EB-2017-0049, DRO Exhibit 3.1, Tab I3-TB Data).

**Response:**

a) The Hydro One Forecast of OM&A and Capital cost was not based on identifying work at a USofA account level. An allocation of the OPDC incremental OM&A and Capital costs to the requested USofA account level used in Tab I3 of the allocation model would not accurately reflect the work captured in the forecast amounts.

   In Attachment 1 to this response, Hydro One has provided further breakdown of the three largest Hydro One Forecast line items in Exhibit A, Tab 1, Schedule 19 Attachment 1 (Operations, Customer Care and Capital line items).

b) See part a) above.

# Attachment 1

| Hydro One Forecast Select Line Items | 2020 Year 1 | 2021 Year 2 | 2022 Year 3 | 2023 Year 4 | 2024 Year 5 | 2025 Year 6 | 2026 Year 7 | 2027 Year 8 | 2028 Year 9 | 2029 Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| **OM&A Expenditures** | | | | | | | | | | |
| Existing Customers[1] | 55 | 137 | 141 | 145 | 149 | 153 | 158 | 163 | 167 | 172 |
| Lines Infastructure | 160 | 394 | 406 | 418 | 430 | 443 | 456 | 469 | 483 | 497 |
| Stations | 356 | 198 | 204 | 210 | 216 | 222 | 229 | 236 | 243 | 250 |
| Operations | 571 | 729 | 750 | 772 | 795 | 818 | 843 | 867 | 893 | 919 |
| Collections | 39 | 96 | 99 | 97 | 98 | 100 | 101 | 102 | 104 | 105 |
| Billing | 102 | 237 | 238 | 250 | 253 | 257 | 260 | 264 | 267 | 270 |
| Call Center | 143 | 350 | 356 | 361 | 366 | 371 | 377 | 382 | 388 | 393 |
| Bad Debt | 41 | 99 | 100 | 98 | 100 | 101 | 103 | 104 | 106 | 107 |
| Customer Care | 325 | 782 | 793 | 806 | 817 | 829 | 841 | 852 | 864 | 876 |
| **Capital Expenditures** | | | | | | | | | | |
| Existing Customers[1] | 433 | 215 | 221 | 228 | 234 | 241 | 249 | 256 | 263 | 271 |
| Lines Infastructure | 144 | 355 | 365 | 376 | 387 | 399 | 411 | 423 | 435 | 448 |
| Stations | 215 | 531 | 546 | 562 | 579 | 596 | 614 | 632 | 650 | 669 |
| Growth | 513 | 1,267 | 1,303 | 1,341 | 1,379 | 1,560 | 1,517 | 1,546 | 1,577 | 1,608 |
| Capital | 1,305 | 2,368 | 2,436 | 2,507 | 2,579 | 2,796 | 2,790 | 2,857 | 2,926 | 2,997 |

Note:
[1] The bulk of the costs in "Existing Customers" relates to metering sustainment activities.

# VECC INTERROGATORY # 10

**Reference:**

Exhibit A/Tab 2/Schedule 1, page 2 (Table 1)
EB-2016-0276, Exhibit I, Tab 3, Schedule 13

**Interrogatory:**

a) Please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 13 part (a) to include 2017 and 2018.

b) If the average spending for the 2017-2018 period is materially different from that in the Year 1 Status Quo Forecast, please explain why.

**Response:**

a)

| STATUS QUO FORECAST - YEAR 1 - CAPITAL EXPENDITURES (CAPEX) | 3,431,000 |
|---|---|

**OPDC HISTORICAL CAPITAL EXPENDITURES FROM 2013 - 2018**

| | | |
|---|---|---|
| 2013 CAPEX - per Audited FS | 2,724,000 | -20.6% |
| 2014 CAPEX - per Audited FS | 3,265,000 | -4.8% |
| 2015 CAPEX - per Audited FS | 2,311,000 | -32.6% |
| 2016 CAPEX - per Audited FS | 5,565,000 | 62.2% |
| 2017 CAPEX - per Audited FS | 3,549,000 | 3.4% |
| 2018 CAPEX - per Audited FS | 2,377,000 | -30.7% |
| **Average CAPEX 2013 - 2018** | **3,299,000** | **-3.8%** |

b) The average spending over the last six years on capital was $3,299,000. This amount is lower than the year one status quo forecast by 3.8%.

OPDC does not consider this difference material given that total capital expenditures can vary greatly from year to year depending on the projects involved.

# VECC INTERROGATORY # 11

**Reference:**

Exhibit A/Tab 2/Schedule 1, page 3 (lines 1-7)
EB-2017-0049, DRO, Exhibit 3.1

**Interrogatory:**

a) Please confirm that the 2017 HONI OM&A costs and customer counts used to derive the $179/customer cost for high density (UR) residential class are forecast values whereas the 2017 OM&A costs and customer counts for OPDC are actual values.

b) Please provide a schedule that compares the HONI's total forecast versus actual 2017 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the 2017 DRO (EB-2016-0081) with the actual 2017 customer counts. (Note: Please include the individual forecast and actual customer/connection count for all HONI's customer classes).

c) Footnote #3 states: "For the OPDC residential class … the cost to serve is estimated to be $208/customer". Please provide the calculations supporting this statement.

d) Based on HONI's 2017 DRO (EB-2016-0081), what are the OM&A costs per customer to serve the UGe and UGd customer classes?

e) Based on the last Cost Allocation model submitted by OPDC to the Board, what percentage of total OM&A costs were allocated to the Residential, GS<50 and GS>50 customer classes?

f) Based on the HONI's EB-2017-0049 Draft Rate Order Filing, Exhibit 3.1 (i.e., the related cost allocation model), please provide the forecast 2018 customer count, OM&A cost and OM&A costs per customer for the high density (UR) residential class.

g) Based on HONI's EB-2017-0049 DRO, what are the OM&A costs per customer to serve the UGe and UGd customer classes?

h) Please provide a schedule that compares the HONI's total forecast versus actual 2018 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the EB-2017-0049 DRO with the actual 2018 customer counts. (Note: Please include the individual forecast and actual customer/connection count for all HONI's customer classes).

i) Please provide OPDC's actual 2018 actual OM&A costs, customer count (consistent with the definition used in the OEB Yearbook) and the resulting 2018 OM&A cost per customer.

j) For those areas that HONI has currently designated as "high density", what is the average number of customers per km?

**Response:**

a) Confirmed.

b) The table below provides the requested information.

| | **Forecast (as filed in 2017 DRO)** | **Actuals (2017)** |
|---|---|---|
| **OM&A** | $594.0 million | $558.7 million |
| **Total Number of Customers** | 1,312,485 | 1,295,709 |
| **UR** | 213,918 | 215,844 |
| **R1** | 445,243 | 447,647 |
| **R2** | 334,551 | 330,514 |
| **Seasonal** | 155,033 | 147,253 |
| **GSe** | 94,081 | 88,523 |
| **GSd** | 6,282 | 5,231 |
| **UGe** | 17,851 | 17,747 |
| **UGd** | 1,913 | 1,711 |
| **St Lgt*** | 20,700 | 22,595 |
| **Sen Lgt*** | 14,836 | 11,381 |
| **USL** | 5,734 | 5,455 |
| **Dgen** | 1,523 | 1,004 |
| **ST** | 822 | 805 |

*Number of connections used for cost allocation purposes.

c) Please refer to Attachment 1 of this interrogatory response.

d) The average OM&A cost per customer in HONI's UGe and UGd rate classes are calculated by dividing the approved forecast 2017 OM&A cost allocated to each rate class by the approved 2017 forecast number of customers used to determine the Hydro One's 2017 draft rates (EB-2016-0081). The values are shown in the table below.

| Rate Class | OMA per Customer |
|---|---|
| UGe | $ 476 |
| UGd | $ 5,068 |

e) The allocations were 59.9%, 16.9%, and 18.4%, respectively. Please refer to Attachment 2 of this interrogatory response for details regarding these calculations.

f) The average OM&A cost per customer in Hydro One's UR rate class is calculated by dividing the approved forecast 2017 OM&A cost allocated to each rate class by the approved 2017 forecast number of customers used to determine the Hydro One's 2017 draft rates (EB-2016-0081). The values are shown in the table below.

| Rate Class | OMA per UR Customer |
|---|---|
| UR | $ 176 |

g) The average OM&A cost per customer in Hydro One's UGe and UGd rate classes are calculated by dividing the approved forecast 2018 OM&A cost allocated to each rate class by the approved 2018 forecast number of customers used to determine the Hydro One's 2018 draft rates (EB-2017-0049). The values are shown in the table below.

| Rate Class | OMA per Customer |
|---|---|
| UGe | $ 447 |
| UGd | $ 5,028 |

h) The table below provides the requested information.

| | **Forecast (as used in CAM submitted in EB-2017-0049 DRO)** | **Actuals (2018)** |
|---|---|---|
| **OM&A** | $544.4 million | $560.3 million |
| **Total Number of Customers** | 1,303,822 | 1,307,005 |
| **UR** | 227,025 | 227,468 |
| **R1** | 447,465 | 452,894 |
| **R2** | 328,479 | 328,811 |
| **Seasonal** | 147,679 | 145,650 |
| **GSe** | 87,902 | 88,019 |
| **GSd** | 5,239 | 5,340 |
| **UGe** | 18,000 | 17,967 |
| **UGd** | 1,735 | 1,736 |
| **St Lgt*** | 21,581 | 20,846 |
| **Sen Lgt*** | 11,301 | 10,938 |
| **USL** | 5,490 | 5,479 |
| **Dgen** | 1,119 | 1,064 |
| **ST** | 807 | 793 |

i) Please refer to Attachment 1 of this interrogatory response.

j) The average number of customers per km for those areas that Hydro One has currently designated as “high density” is about 69 customers per km.

| **OPDC Income Statement**<br>**For the year ended December 31** | | **2017** | | **2018** |
|---|---|---|---|---|
| **Power and Distribution Revenue** | $ | 44,516,008 | $ | 44,393,934 |
| **Cost of Power and Related Costs** | | 36,061,333 | | 35,822,451 |
| **Distribution Revenue** | | 8,454,675 | | 8,571,483 |
| **Other Income (Loss)** | | (72,487) | | (245,800) |
| **Expenses** | | | | |
| Operating | | 1,009,373 | | 1,105,352 |
| Maintenance | | 1,103,593 | | 1,198,663 |
| Administrative | | 2,759,020 | | 2,752,028 |
| Depreciation and Amortization | | 1,183,380 | | 1,222,768 |
| Financing | | 812,727 | | 840,935 |
| | | 6,868,093 | | 7,119,746 |
| **Net Income Before Taxes** | | 1,514,095 | | 1,205,937 |
| **PILs and Income Taxes** | | | | |
| Current | | 59,000 | | 169,000 |
| Deferred | | 239,000 | | (140,000) |
| | | 298,000 | | 29,000 |
| **Net Income (Loss)** | | 1,216,095 | | 1,176,937 |
| Other Comprehensive Income (Loss) | | - | | - |
| **Comprehensive Income (Loss)** | $ | 1,216,095 | $ | 1,176,937 |

| | | | | |
|---|---|---|---|---|
| Actual OM&A costs | | 4,871,986 | | 5,056,043 |
| Customer count | | 13,830 | | 14,091 |
| OM&A per Customer | $ | 352 | $ | 359 |
| % OM&A costs allocated to residential rate class | | 59% | | 59% |
| Residential customer count | | 12,284 | | 12,522 |
| OM&A per Residential customer (estimated) | $ | 208 | $ | 212 |

| **OPDC Customer Count**<br>**For the year ended December 31** | **2017** | **2018** |
|---|---|---|
| **Residential Customers** | | |
| Number of Customers | 12,284 | 12,522 |
| **General Service <50kW Customers** | | |
| Number of Customers | 1,382 | 1,404 |
| **General Service >50kW, Large User (>5000kW) and Sub Transmission** | | |
| Number of GS >50kW Customers | 164 | 165 |
| **Total customer count** | **13,830** | **14,091** |

| | Total OM&A | Residential OM&A | GS <50 OM&A | GS>50 OM&A |
|---|---|---|---|---|
| **OM&A** | | | | |
| Distribution Costs | $1,783,000 | $939,734 | $292,094 | $416,113 |
| Customer Related Costs | $1,081,000 | $780,005 | $191,790 | $106,961 |
| General and Administration | $1,482,000 | $884,176 | $250,602 | $274,577 |
| | $4,346,000 | $2,603,915 | $734,486 | $797,651 |
| | 95.2% | 59.9% | 16.9% | 18.4% |

*Source: Orillia_RA10_CA Model Run 2*

# VECC INTERROGATORY # 12

**Reference:**

Exhibit A/Tab 2/Schedule 1, page 3 (line 11) to page 6
EB-2016-0276, Exhibit I, Tab 3, Schedule 16

**Interrogatory:**

a) The Application states (page 5) that OPDC's last rate order was approved in EB-2017-0264. Please confirm that a more recent rate order has now been approved by the OEB effective May 1, 2019 (EB-2018-0061).

b) Does this new rate order change OPDC's base distribution rates or the bill impacts in Table 2 attributed to "Change in Distribution Delivery Rates" or "Total Bill"? If yes please provide a revised version of Table 2.

c) Please update Table 3, as required, based on the EB-2018-0061 Decision and Rate Order.

d) Based on the EB-2018-0061 Decision and Rate Order and HONI's current EB-2017-0049 DRO, please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 16, part (a).

e) What would have been the impact on OPDC's 2017 revenue from specific service charges if HONI's currently approved charges (per EB-2017-0049) were used instead of OPDC's 2017 approved charges?

**Response:**

a) Confirmed.

b) In light of the ongoing MAAD proceeding, OPDC did not apply for Price Cap adjustment to its distribution rates for 2019. As a result, OPDC's latest rate order (EB-2018-0061) only slightly impacts the "Base Distribution Charges" for the Residential class (because of the move to all-fixed distribution rates). "Total Bill" calculations have been updated to reflect the latest commodity and regulatory prices, updated Retail Transmission Service Rates (RTSR), and removal of the

Deferral/Variance Account rate riders that expired on April 30, 2019. Below is the updated Table 2:

| | Change in Base Distribution Rates (%) | Change in Total Bill (%) |
|---|---|---|
| Residential | -0.99% | -0.26% |
| General Service Less Than 50kW | -1.08% | -0.28% |
| General Service 50 to 4,999 kW | -0.97% | -0.07% |

c) Below is the updated Table 3 (Exhibit A, Tab 2, Schedule 1):

| Current Rider Description | Proposed Rider Description or Amendments in Proposed OPDC 2020 Rate Schedules |
|---|---|
| Rate Rider for Smart Meter Incremental Revenue Requirement - in effect until the effective date of the next cost of service-based rate order | In effect until the effective date of the next cost of service-based rate order |
| Smart Metering Entity Charge[1] - effective until December 31, 2022 | Will remain in effect until December 31, 2022 |
| Rate Rider for Application of Tax Change (2019) - effective until April 30, 2020 | This Rider expires in April, 2020. It will be deleted if the transaction closes after this date. |

[1] The Smart Metering Entity Charge is a component of the "Distribution Charge" on a customer's bill, established by the OEB through a separate order. Decision and Order, EB-2017-0290, March 1, 2018

d) Please refer to Exhibit I, Tab 1, Schedule 13.

e) Due to the increase in pole attachment charges and the elimination of certain charges that are to be levied by all LDCs, the overall impact to OPDC's revenue from specific service charges if Hydro One's rates were used would have been a reduction of approximately $40,000.

# VECC INTERROGATORY # 13

**Reference:**
Exhibit A/Tab 2/Schedule 1, pages 8-11
EB-2016-0276, Exhibit I, Tab 3, Schedule 17
OEB Electricity Reporting and Record Keeping Requirements (RRR)

**Interrogatory:**

a) If available, please update Table 4 to include 2018 (either all or as much of the year as information for both utilities is available).

b) With respect to Table 4, please provide the contribution to the reliability metrics for HONI and OPDC for the following cause codes for the years 2016-2018:
   - Scheduled Outages
   - Tree Contacts
   - Defective Equipment

c) Please update the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 17, part c) to include 2016 to 2018.

**Response:**

a) The updated is provided below

| | 2014 | 2014 | 2015 | 2015 | 2016 | 2016 | 2017 | 2017 | 2018 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|
| | Hydro One | Orillia Power | Hydro One | Orillia Power | Hydro One | Orillia Power | Hydro One | Orillia Power | Hydro One | Orillia Power |
| Duration (SAIDI) | 0.57 | 2.15 | 3.16 | 1.06 | 2.76 | 0.52 | 4.31 | 3.63 | 2.06 | 1.43 |
| Frequency (SAIFI) | 0.30 | 1.28 | 1.01 | 2.44 | 0.83 | 1.10 | 1.20 | 0.92 | 0.81 | 1.50 |

b) The following table stratifies the overall reliability metrics excluding loss of supply for OPDC and Hydro One provided in Table 3 by the cause codes - scheduled outages, tree contacts and defective equipment.

| | 2016 | | 2017 | | 2018 | |
|---|---|---|---|---|---|---|
| | **Hydro One** | **OPDC** | **Hydro One** | **OPDC** | **Hydro One** | **OPDC** |
| **Duration (SAIDI)** | 2.76 | 0.52 | 4.31 | 3.63 | 2.06 | 1.43 |
| **Frequency (SAIFI)** | 0.83 | 1.10 | 1.20 | 0.92 | 0.81 | 1.50 |
| **Scheduled Outages Contribution** | | | | | | |
| **Duration (SAIDI)** | 0.00 | 0.22 | 0.00 | 0.18 | 0.00 | 0.06 |
| **Frequency (SAIFI)** | 0.00 | 0.08 | 0.00 | 0.08 | 0.00 | 0.04 |
| **Tree Contacts Contribution** | | | | | | |
| **Duration (SAIDI)** | 2.25 | 0.02 | 3.38 | 0.00 | 1.83 | 0.10 |
| **Frequency (SAIFI)** | 0.71 | 0.02 | 0.80 | 0.00 | 0.69 | 0.08 |
| **Defective Equipment Contribution** | | | | | | |
| **Duration (SAIDI)** | 0.51 | 0.04 | 0.02 | 0.86 | 0.23 | 0.10 |
| **Frequency (SAIFI)** | 0.13 | 0.04 | 0.02 | 0.35 | 0.11 | 0.08 |

c) The following statistics are as documented by the OEB through the annual OEB Yearbook for the years 2016 and 2017. Please note that the 2018 Yearbook has not been published yet by the OEB. Additionally, please note that the data provided compares OPDC, a largely urban utility, against all of Hydro One, a predominantly rural utility. The regional granularity provided for the comparison of SAIDI and SAIFI in Table 3 is not readily available for these other metrics.

## Unitized Statistics and Service Quality Requirements

| | **2016** | | **2017** | |
|---|---|---|---|---|
| | **Hydro One** | **OPDC** | **Hydro One** | **OPDC** |
| Low Voltage Connections (OEB Min. Standard: 90%) | 98.60 | 100.00 | 98.06 | 100.00 |
| High Voltage Connections (OEB Min. Standard: 90%) | N/A | 100.00 | N/A | 100.00 |
| Telephone Accessibility *(OEB Min. Standard: 65%)* | 74.20 | 96.60 | 81.85 | 97.43 |
| Appointments Met *(OEB Min. Standard: 90%)* | 99.50 | 100.00 | 98.94 | 100.00 |
| Written Response to Enquiries *(OEB Min. Standard: 80%)* | 100.00 | 100.00 | 100.00 | 100.00 |
| Emergency Urban Response *(OEB Min. Standard: 80%)* | N/A | 100.00 | N/A | 100.00 |
| Emergency Rural Response *(OEB Min. Standard: 80%)* | 75.30 | N/A | 77.28 | N/A |
| Telephone Call Abandon Rate *(OEB Standard: not exceed 10%)* | 2.70 | 0.10 | 2.14 | 0.03 |
| Appointments Scheduling *(OEB Min. Standard: 90%)* | 99.50 | 97.00 | 98.96 | 97.72 |
| Rescheduling a Missed Appointment *(OEB Standard: 100%)* | 98.50 | N/A | 99.65 | N/A |
| Reconnection Performance Standards *(OEB Min. Standard: 85%)* | 98.50 | 100.00 | 98.19 | 100.00 |
| New Micro-embedded Generation Facilities Connected *(OEB Min. Standard: 90%)* | 99.22 | 100.00 | 99.77 | 100.00 |
| Billing Accuracy *(OEB Min. Standard: 98%)* | 99.04 | 99.98 | 99.28 | 99.98 |

# VECC INTERROGATORY # 14

**Reference:**

Exhibit A/Tab 2/Schedule 1, page 11 (lines 25) to page 12 (line 2)
EB-2016-0276, Exhibit I, Tab 3, Schedule 14

**Interrogatory:**

a) With respect to the response to EB-2016-0276, Exhibit I, Tab 3, Schedule 14, part c), please indicate where in HON's EB-2017-0049 Application the details regarding the capital costs for the new operations centre in Orillia can be found.

**Response:**

Details regarding the capital costs associated with the Integrated System Operations Centre that will be located in Orillia are documented in Exhibit B, Tab 1, Schedule 1, ISD: GP-18 of EB-2017-0049.

# VECC INTERROGATORY # 15

**Reference:**
Exhibit A/Tab 2/Schedule 1, pages 17-19

**Interrogatory:**
a) Does OPDC currently have a local office/location where customer can pay their bills in person (i.e., not a drop-off box but a location staffed by OPDC)?

b) If yes, will a similar location/service exist after the integration of OPDC?

**Response:**
a) Yes

b) No

# VECC INTERROGATORY # 16

**Reference:**
Exhibit A/Tab 2/Schedule 1, page 23 (lines 1-22)

**Interrogatory:**

a) Will utilizing US GAAP alter any of the depreciation rates or recorded asset values in OPDC's financial statements or have any other "cost" implications?

b) If yes, please describe the impacts and whether HON will be requesting any new deferral/variance accounts to record these impacts until the time of the rebasing.

**Response:**

a) Hydro One plans to change the depreciation rates for OPDC after the acquisition. Please see response to Exhibit I, Tab 2, Schedule 4 and Exhibit I, Tab 2, Schedule 15.

b) Please see response to Exhibit I, Tab 2, Schedule 15.

# VECC INTERROGATORY # 17

**Reference:**
Exhibit A/Tab 3/Schedule 1, pages 1-7 Attachment 18
EB-2016-0276, Exhibit A/Tab 3/Schedule 3, page 7 (Table 6)

**Interrogatory:**

a) Please explain the following changes in the forecast for 2025 from the EB-2016-0276 Application (Table 6) to the current application (Table 2 on page 7):
   i. Rate Base – increases from $45.4 M to $47.9 M
   ii. Revenue – increases from $9.2 M to $9.3 M
   iii. OM&A – decreases from $2.237 M to $2.075 M.

b) Please provide a schedule that sets out the calculation of the OM&A values included in Table 2 (including the risk factor adjustment) and reconcile with the Hydro One Forecast OM&A costs in Table 1 (Exhibit A, Tab 2 Schedule 1).

c) Attachment 18 states that the Hydro One Residual scenario is calculated based on the same model used by Hydro One in the calculation of the ESM. Given this statement please explain the following variances between the 2029 values in the ESM calculation (page 7, Table 2) and Attachment 18:
   - Rate Base - $54.722 M vs. $51.215 M
   - Cost of Debt (Interest) - $1.944 M vs. $1.329 M

d) With respect to Table 1 (page 5), please explain how the working capital component of the rate base was determined and, in particular the basis for the assumptions made regarding the cost of power.

e) With respect to Table 1, please explain more fully the basis for the depreciation rates that will applied to the acquired assets during the 10-year deferral period. In particular, does Hydro One plan on specifically reviewing the useful life of the acquired assets and resetting the depreciation rates accordingly?
   i. If yes, does Hydro One plan on establishing a deferral/variance account to capture any differences in depreciation charges for these assets until the time of rebasing?

ii. How can the ESM values in Table 2 be "locked in" at this point in time if the depreciation rates are yet to be determined?

iii. If the depreciation rates for the acquired assets have already been set, how do they compare with OPDC's current rates? If there is a difference, does Hydro One plan on establishing a deferral/variance account to capture the differences in depreciation charges for these assets until the time of rebasing? If not, why not?

**<u>Response:</u>**

a) For the driver prominently responsible for the minor increases to Rate Base, Revenue and OM&A that have occurred over the passage of time between the application of EB-2016-0276 and the current Application, please refer to Exhibit I, Tab 2, Schedule 3 part g.

b) A schedule reconciling the OM&A in *Table 2* of the ESM provided in Exhibit A, Tab 3, Schedule 3, to the Hydro One Residual OM&A provided in Table 1 of Exhibit A, Tab 2, Schedule 1, is provided below.

| *Period* | **6** | **7** | **8** | **9** | **10** |
|---|---|---|---|---|---|
| *Year* | **2025** | **2026** | **2027** | **2028** | **2029** |
| (000's) | | | | | |
| OM&A<br>(per Table 2, Exhibit A, Tab 3 Schedule 1) | 2,075 | 2,120 | 2,166 | 2,212 | 2,260 |
| | | | | | |
| Deduct the 20% OM&A Risk factor | (20%) | (20%) | (20%) | (20%) | (20%) |
| | | | | | |
| OM&A<br>(per Table 1, Exhibit A, Tab 2 Schedule 1) | 1,729 | 1,767 | 1,805 | 1,844 | 1,883 |

c) Attachment 18 is provided by Hydro One to provide detail information on how Hydro One's Year 11 revenue requirement was forecast for the purposes of showing what the expected Future Rate structures will be in 2030. In this attachment, Hydro One's Residual rate base forecast estimates and revenue requirement values are based on capital parameters that most likely would apply to Hydro One at the time of rebasing.

The ESM calculation, in comparison, uses the economic parameters that were approved by the OEB in OPDC's last cost of service application. .

Table 1 of Exhibit A, Tab 3, Schedule 1 (for the ESM modeling) and Attachment 20 of the prefiled evidence (for the Hydro One Year 11 forecast) summarize the assumptions used in the two tables.

d) Please refer to Attachment 1 of Exhibit I, Tab 2, Schedule 13, the excel tab named "Working Capital" for the calculation of working capital in the Hydro One ESM.

e) Please refer to Exhibit I, Tab 2, Schedule 13.
   i. Please refer to Exhibit I, Tab 1, Schedule 17 and Exhibit I, Tab 2, Schedule 15.
   ii. The depreciation rates that Hydro One will be using are known. The acquired OPDC assets will be moved into corresponding Hydro One asset categories and depreciated at those categories rates thereafter.
   iii. Please refer to part i above.

# VECC INTERROGATORY # 18

**Reference:**

Exhibit A/Tab 3/Schedule 1, pages 3-6
EB-2016-0276, Exhibit I, Tab 4, Schedule 16

**Interrogatory:**

a) Please provide a schedule that sets out the load and customer count forecasts (by customer class) as used in EB-2016-0276 and in the current Application to project the revenues used in the calculation of the ESM. (Note: For the starting year, please use the last year for which actual values were available in EB-2016-0276. For both the EB-2016-0276 and current Application, please report actual values where applicable.)

**Response:**

Attachment 1 to this Exhibit provides the load and customer count forecasts as used in EB-2016-0276 and in the current Application for the Residential and General Service rate classes. Revenues for the "Other" rate classes (including Street Lights, Sentinel Lights and Unmetered Scattered Load) were held constant at the last OEB approved values in the calculation of the ESM.

| EB-2018-0270_Customer Count Forecast | | | | |
|---|---|---|---|---|
| **Year** | **Residential** | **General Service <50kW** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 11,627 | 1,352 | 167 | Actual |
| 2013 | 11,702 | 1,349 | 168 | Actual |
| 2014 | 11,816 | 1,358 | 166 | Actual |
| 2015 | 11,916 | 1,361 | 168 | Actual |
| 2016 | 12,028 | 1,382 | 160 | Actual |
| 2017 | 12,284 | 1,382 | 164 | Actual |
| 2018 | 12,398 | 1,394 | 165 | Forecast |
| 2019 | 12,512 | 1,406 | 166 | Forecast |
| 2020 | 12,626 | 1,418 | 168 | Forecast |
| 2021 | 12,741 | 1,430 | 169 | Forecast |
| 2022 | 12,857 | 1,442 | 170 | Forecast |
| 2023 | 12,975 | 1,454 | 171 | Forecast |
| 2024 | 13,093 | 1,467 | 172 | Forecast |
| 2025 | 13,224 | 1,481 | 174 | Forecast |
| 2026 | 13,349 | 1,494 | 175 | Forecast |
| 2027 | 13,474 | 1,507 | 176 | Forecast |
| 2028 | 13,599 | 1,519 | 178 | Forecast |
| 2029 | 13,724 | 1,532 | 179 | Forecast |

| EB-2016-0276_Customer Count Forecast | | | | |
|---|---|---|---|---|
| **Year** | **Residential** | **General Service <50kW** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 11,627 | 1,352 | 167 | Actual |
| 2013 | 11,702 | 1,349 | 168 | Actual |
| 2014 | 11,816 | 1,358 | 166 | Actual |
| 2015 | 11,918 | 1,367 | 167 | Forecast |
| 2016 | 12,029 | 1,378 | 168 | Forecast |
| 2017 | 12,142 | 1,391 | 169 | Forecast |
| 2018 | 12,254 | 1,404 | 171 | Forecast |
| 2019 | 12,367 | 1,417 | 172 | Forecast |
| 2020 | 12,479 | 1,430 | 173 | Forecast |
| 2021 | 12,593 | 1,443 | 174 | Forecast |
| 2022 | 12,708 | 1,456 | 176 | Forecast |
| 2023 | 12,824 | 1,469 | 177 | Forecast |
| 2024 | 12,940 | 1,483 | 178 | Forecast |
| 2025 | 13,070 | 1,498 | 180 | Forecast |
| 2026 | 13,193 | 1,512 | 181 | Forecast |
| 2027 | 13,316 | 1,526 | 182 | Forecast |
| 2028 | 13,440 | 1,540 | 184 | Forecast |
| 2029 | 13,564 | 1,553 | 185 | Forecast |

| EB-2018-0270_Sales Forecast (GWh) | | | | |
|---|---|---|---|---|
| **Year** | **Residential** | **General Service <50kW** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 104.3 | 46.0 | 147.6 | Actual |
| 2013 | 106.6 | 45.7 | 144.1 | Actual |
| 2014 | 107.1 | 45.7 | 151.6 | Actual |
| 2015 | 104.7 | 44.3 | 150.2 | Actual |
| 2016 | 103.9 | 43.2 | 150.0 | Actual |
| 2017 | 102.4 | 43.5 | 154.7 | Actual |
| 2018 | 102.2 | 43.3 | 154.4 | Forecast |
| 2019 | 102.0 | 43.2 | 154.4 | Forecast |
| 2020 | 101.4 | 43.0 | 154.1 | Forecast |
| 2021 | 101.2 | 43.0 | 154.1 | Forecast |
| 2022 | 101.3 | 43.1 | 154.6 | Forecast |
| 2023 | 101.3 | 43.2 | 155.0 | Forecast |
| 2024 | 101.7 | 43.5 | 155.9 | Forecast |
| 2025 | 101.6 | 43.5 | 156.1 | Forecast |
| 2026 | 101.7 | 43.7 | 156.6 | Forecast |
| 2027 | 101.9 | 43.8 | 157.2 | Forecast |
| 2028 | 102.3 | 44.1 | 158.2 | Forecast |
| 2029 | 102.2 | 44.1 | 158.2 | Forecast |

| EB-2016-0276_Sales Forecast (GWh) | | | | |
|---|---|---|---|---|
| **Year** | **Residential** | **General Service <50kW** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 104.3 | 46.0 | 147.6 | Actual |
| 2013 | 106.6 | 45.7 | 144.1 | Actual |
| 2014 | 107.1 | 45.7 | 151.6 | Actual |
| 2015 | 108.1 | 45.3 | 151.4 | Forecast |
| 2016 | 108.2 | 45.4 | 151.5 | Forecast |
| 2017 | 108.0 | 45.3 | 151.3 | Forecast |
| 2018 | 107.7 | 45.1 | 151.0 | Forecast |
| 2019 | 107.6 | 45.0 | 151.0 | Forecast |
| 2020 | 107.0 | 44.8 | 150.7 | Forecast |
| 2021 | 106.7 | 44.8 | 150.6 | Forecast |
| 2022 | 106.8 | 44.9 | 151.1 | Forecast |
| 2023 | 106.9 | 45.1 | 151.5 | Forecast |
| 2024 | 107.3 | 45.3 | 152.3 | Forecast |
| 2025 | 107.1 | 45.3 | 152.4 | Forecast |
| 2026 | 107.3 | 45.5 | 152.9 | Forecast |
| 2027 | 107.5 | 45.7 | 153.4 | Forecast |
| 2028 | 108.0 | 46.0 | 154.4 | Forecast |
| 2029 | 107.9 | 46.0 | 154.4 | Forecast |

| EB-2018-0270_Peak Forecast (MW) | | |
|---|---|---|
| **Year** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 396 | Actual |
| 2013 | 394 | Actual |
| 2014 | 402 | Actual |
| 2015 | 400 | Actual |
| 2016 | 401 | Actual |
| 2017 | 405 | Actual |
| 2018 | 404 | Forecast |
| 2019 | 404 | Forecast |
| 2020 | 403 | Forecast |
| 2021 | 403 | Forecast |
| 2022 | 404 | Forecast |
| 2023 | 406 | Forecast |
| 2024 | 408 | Forecast |
| 2025 | 408 | Forecast |
| 2026 | 410 | Forecast |
| 2027 | 411 | Forecast |
| 2028 | 414 | Forecast |
| 2029 | 414 | Forecast |

| EB-2016-0276_Peak Forecast (MW) | | |
|---|---|---|
| **Year** | **General Service >50kW** | **Actual/Forecast** |
| 2012 | 396 | Actual |
| 2013 | 394 | Actual |
| 2014 | 402 | Actual |
| 2015 | 404 | Forecast |
| 2016 | 404 | Forecast |
| 2017 | 404 | Forecast |
| 2018 | 403 | Forecast |
| 2019 | 403 | Forecast |
| 2020 | 402 | Forecast |
| 2021 | 402 | Forecast |
| 2022 | 403 | Forecast |
| 2023 | 404 | Forecast |
| 2024 | 407 | Forecast |
| 2025 | 407 | Forecast |
| 2026 | 408 | Forecast |
| 2027 | 410 | Forecast |
| 2028 | 412 | Forecast |
| 2029 | 412 | Forecast |

# VECC INTERROGATORY # 19

**Reference:**

Exhibit A/Tab 4/Schedule 1, page 7 (lines 14-22)

**Interrogatory:**

Preamble:

The referenced portion of the Application lists a number of factors that are likely to be taken into account by both Hydro One and a future OEB Panel in determining the methodology to be used to establish the amount of Shared Costs to be included in rates, including those for former OPDC customers.

a) Does Hydro One Networks consider the impact on rates for former OPDC customers and HONI's legacy customers as being relevant factors for purposes of establishing the methodology for allocating Shared Costs to customer classes or is the consideration of impacts limited to the adjustments that may be made to rates based on the revenue to customer class revenue to cost ratios that are calculated based on the established cost allocation methodology for Shared Costs?

**Response:**

a) The consideration of rate impacts would be limited to the adjustments that may be made to the revenue to cost ratios that result from the cost allocation methodology.

# VECC INTERROGATORY # 20

**Reference:**
Exhibit A/Tab 4/Schedule 1, pages 2-5

**Interrogatory:**
a) The difference in the Year 11 Rate Base as between the Status Quo Scenario (Table 1) and the Residual Cost to Serve Scenario (Table 3) is primarily due to the difference in Working Capital. Please provide the calculations supporting the working capital values used in both tables.

**Response:**
Table 1 below represents the calculations underpinning the working capital calculation assumed in Hydro One's Residual Cost of Serve Scenario for Years 1-11 (2020-2030).

Table 2 below represents the calculations underpinning the working capital calculation assumed in OPDC's Status Quo Cost to Serve Scenario Hydro One's Residual Cost of Serve Scenario for the same periods.

[Note: In providing OPDC's working capital calculations in Table 2 below, OPDC found an error in its Working Capital calculation. The OM&A used in the calculation of Working Capital was **lower** than the status quo forecast provided in Exhibit A, Tab 2, Schedule 1, Table 1 for each of Years 1 to 10, and Year 11 (2030). The impact of using this incorrect lower OM&A for calculating OPDC's Status Quo Rate Base results in a 2030 (year 11) rate base $65 thousand lower than what it should be (i.e. the working capital in the table is understated by $65 thousand).This represents approximately one-tenth of 1% of the OPDC's 2030 rate base of $53.678[1]M. The error does not impact the OPDC rate base when rounded to one decimal point in millions, that of $53.7M. For this reason, Table 1 below has not been corrected for this inadvertent error.]

[1] Update to Exhibit A, Tab 4, Schedule 1, page 2, Table 1.

**Table 1 - Hydro One Residual Cost of Serve Scenario – Working Capital Calculations for periods Year-1 through Year-11**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **(000's)** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| Controllable Expenses | 4,068 | 2,009 | 2,051 | 1,657 | 1,692 | 1,729 | 1,767 | 1,805 | 1,844 | 1,883 | 1,921 |
| Cost of Power | 37,284 | 37,976 | 38,806 | 39,652 | 40,643 | 41,461 | 42,413 | 43,384 | 44,505 | 45,384 | 46,460 |
| Working Capital Base | 41,352 | 39,985 | 40,857 | 41,309 | 42,334 | 43,190 | 44,180 | 45,189 | 46,349 | 47,268 | 48,381 |
| | | | | | | | | | | | |
| Working Capital Rate % | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% | 7.70% |
| | | | | | | | | | | | |
| Working Capital Allowance | **3,184** | **3,079** | **3,146** | **3,181** | **3,260** | **3,326** | **3,402** | **3,480** | **3,569** | **3,640** | **3,725** |

**Table 2 - OPDC Status Quo Cost to Serve Scenario – Working Capital Calculations for periods Year-1 through Year-11**

| **Year** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **(000's)** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| Controllable Expenses | 4,830 | 4,928 | 5,028 | 5,129 | 5,231 | 5,335 | 5,442 | 5,550 | 5,660 | 5,772 | 5,888 |
| Cost of Power | 36,510 | 37,494 | 44,371 | 45,390 | 46,435 | 47,500 | 48,592 | 49,712 | 50,856 | 52,028 | 53,229 |
| Working Capital Base | 41,340 | 42,422 | 49,399 | 50,519 | 51,666 | 52,835 | 54,034 | 55,262 | 56,516 | 57,800 | 59,117 |
| | | | | | | | | | | | |
| Working Capital Rate % | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% |
| | | | | | | | | | | | |
| Working Capital Allowance | **3,101** | **3,182** | **3,705** | **3,789** | **3,875** | **3,963** | **4,053** | **4,145** | **4,239** | **4,335** | **4,434** |

# VECC INTERROGATORY # 21

**Reference:**

Updated Exhibit A/Tab 4/Schedule 1, page 8 (lines 5-10)

**Interrogatory:**

Preamble:

At page 8 the Application states: "Hydro One proposes within the harmonization and rebasing application following the deferral period, that it would ensure that the total cost, including a portion of Hydro One's Shared Costs, to be collected from the former OPDC customers would be between, (a) the Residual Cost to Serve scenario plus LV charges (totaling $7.9 M); and (b) the Year 11 revenue requirement under the OPDC Status Quo scenario plus Year 11 LV charges (totaling $14.4 M)." (Emphasis Added)

a) The choice of the word "collected" as opposed to say "allocated" suggests that HON is proposing that regardless of the results of the cost allocation methodology that will be used at the time of the harmonization and rebasing application, HON will (at that time) propose a revenue to cost ratio for the customer class representing the former OPDC customers such that the resulting rates will result in revenues between the two values referenced in the quote. Please confirm whether or not this is the intent of HONI's proposal as set out in the Preamble. If it is not, please clarify what HONI is proposing.

b) If response to part (a) is yes, would a similar approach be used in subsequent rebasing applications? If so, how would the values for the Residual Cost to Serve and OPDC Status Quo cost to serve be established? If a similar approach is not to be used, how will HON ensure that in subsequent rebasing Applications former OPDC customers will continue to pay less than they would have if the transaction had not occurred?

c) If the response to part (a) is yes and the resulting revenues produce a revenue to cost ratio that is below the policy range established by the Board, would it be HONI's intent that any shortfall in revenue be recovered from the other customer classes?

**Response:**

a) Yes, that is Hydro One's intent. Hydro One will use the results of the cost allocation model to establish a revenue-to-cost ratio for the customer class representing the former OPDC customers such that the resulting rates will result in revenues between the two values referenced in the quote.

b) No, in subsequent rebasing applications Hydro One will not compare the revenues to be collected against the two values referenced in the quote. The magnitude of the bill impact on all customers, including former OPDC customers, resulting from the Board's cost allocation and rate design policies in effect at the time would be a consideration in Hydro One's rate proposals at that time.

There is also no basis for reliably establishing what the OPDC status quo costs would have been in subsequent rebasing applications (i.e. 16 years into the future and beyond). As such, it is not realistic, or reasonable, to indefinitely continue comparing former OPDC customers' revenues against would have been collected from them if the transaction had not occurred.

c) Hydro One's MAAD Application commits to charging OPDC customers no more than the higher goal post amount of $14.4M. Under this scenario $6.5M ($14.4 - $7.9) in synergy and efficiency cost savings would accrue to the benefit of Hydro One's legacy customers, and OPDC customers would not be harmed as they would still be paying no more than what they would have been paying had they not been acquired. If the initial results from the cost allocation and rate design process results in total costs in excess of $14.4M being borne by OPDC customers (which is not expected to be the case as shown in the response to Exhibit I, Tab 1, Schedule 9), this would mean that Hydro One's legacy customers would be getting *more than* $6.5M in costs savings. In that situation Hydro One would propose a reduction in the revenue-to-cost ratios for the OPDC classes such that the costs to be borne by OPDC customers would not exceed $14.4M. While a reduction to the revenue-to-cost ratios for the OPDC customer classes would shift some costs to be collected to other Hydro One classes, this would not result in harm to Hydro One legacy classes but rather simply reduce the benefit that is accruing to them to the maximum value of $6.5M.

# VECC INTERROGATORY # 22

**Reference:**

Exhibit A/Tab 4/Schedule 1, page 9 (lines 13-22)

**Interrogatory:**

Preamble:

The Application states that to calculate the Status Quo forecast in Year 11 Hydro One will use the forecast as provided in the current Application but that it would need to be adjusted for: i) unforeseen costs and ii) the weighted average cost of capital applicable at the time.

a) Are there any other factors that would need to be accounted for such as: i) changes in working capital due to changes in the expected load, the expected cost of power or the working capital allowance percentage or ii) changes in tax rates?

**Response:**

a) In Year 11, Hydro One will need to confirm the Year 11 Status Quo forecast of where OPDC's revenue requirement would have been in absence of the transaction. OPDC has provided a forecast of its OM&A and capital in Year 11. Hydro One in determining the Status Quo revenue requirement would start with the key costs supplied by OPDC, in Attachment 18: OM&A, Depreciation and Rate Base. If there was a major event that resulted in a substantive increase in capital expenditure and/or OM&A, Hydro One would also add these to the revenue requirement calculations.

"Unknown or unforeseen" costs that could be added are those that would have been incurred by OPDC in absence of the transaction and would have impacted OPDC's status quo revenue requirement. Examples include: major storms resulting in significant damage to distribution assets; new environmental legislation requiring the retirement and replacement of certain assets; changes to OEBs policies and rules (e.g. change in capital structure); changes to tax policies and rates, etc.

Items such as a change in union wage rates would not be included nor would minor changes to interest or inflation rates used to determine the forecast provided.

If there was a change in the Status Quo forecast as a result of any of these factors, Hydro One would provide evidence to the Board at the time of harmonization to explain any variances.

Once the operating costs have been determined, the revenue requirement for the status quo in Year 11 would be calculated using the OEB's then-current economic parameters and tax rates.

# VECC INTERROGATORY # 23

**Reference:**

Exhibit A/Tab 5/Schedule 1, page 3 (lines 4-19) and page 8 (lines 1-2)
EB-2017-0049, Exhibit C1/Tab 1/Schedule 1, page 2, Table 1

**Interrogatory:**

Preamble:
The Supplemental Evidence states: "The OEB's cost allocation model uses fixed assets as the primary allocator for the costs of operating and maintaining distribution assets and since Hydro One proposes to use the principles embedded within the cost allocation model to allocate all other OM&A costs (e.g., customer, and administration and general costs), Hydro One will only track OPDC's incremental OM&A costs until the time that OPDC is harmonized into Hydro One's rate structure."

It also states: "Hydro One cannot track, on an actual basis, either during the deferral period or after, the costs associated with certain Hydro One resources that OPDC customers will enjoy the benefit of (i.e., those resources that are also required by and paid for by legacy customers). These costs, referred to as Shared Costs in Exhibit A, Tab 4, Schedule 1 (page 6 of 12) of this Application, include costs that cannot be directly associated with serving a specific group of customers."

The Supplemental Evidence further states: "Included in Shared Costs are the costs associated with upstream distribution facilities used by former OPDC customers (i.e. costs formerly captured under LV charges").

In EB-2017-0049, Hydro One broke its OM&A expenditures down into five major categories: i) Sustainment, ii) Development, iii) Operations, iv) Customer Care, v) Common Corporate and vi) Property Taxes and Rights Payments.

a) Other than the inclusion of "the costs associated with upstream distribution facilities", are the "Shared Costs" referred to in the Supplemental Evidence synonymous with the "Common Corporate Costs" as defined in EB-2017-0049?

b) If not, specifically what are the differences and, in particular, do Shared Costs include costs other than those considered to be Common Corporate Costs per EB-2017-0049?

c) It is noted that, in Hydro One's cost allocation model, Customer Care costs are not allocated based on fixed assets. Do the incremental costs that Hydro One has identified as being associated with OPDC include any Customer Care costs (e.g. LEAP, incremental meter reading and billing costs, etc.) or are Customer Care costs all considered to be a Shared Cost?

d) If all Customer Care costs are not considered to be Shared Costs, please separately identify: i) the incremental Customer Care costs included in the OPDC's Year 11 Residual Cost to Serve and what activities the costs are associated with and ii) the Customer Care activities (if any) that are considered to be part of Shared Costs.

e) Do the incremental costs that Hydro One has identified as being associated with OPDC include Property Taxes and Rights Payments attributable to OPDC's service area?

**Response:**

a) No. The two types of costs are not synonymous.

Common Corporate Costs as defined in Exhibit C1, Tab 1, Schedule 1, page 4 in EB-2017-0049 includes costs associated with common corporate functions and services (including corporate management, finance, people and culture, corporate relations, general counsel and corporate secretariat, regulatory affairs, security management, internal audit, and real estate and facilities), planning, information technology and cost of external revenues.

In Exhibit A, Tab 4, Schedule 1, page 6 of this application, Hydro One has defined Shared Costs to include: (i) shared facilities used to provide operations and maintenance services (e.g. service centres and maintenance yards), billing and IT systems, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer service and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former OPDC customers (e.g. costs formerly captured under LV charges).

b) Item (ii) in the paragraph above most closely aligns with Common Corporate Costs as defined in EB-2017-0049. Parts (i) and (iii) are additional costs beyond what is included in the Distribution Rates application definition of Common Corporate Costs.

c) and d)

The incremental Customer Care costs associated with serving OPDC customers include activities such as LEAP, meter reading, billing costs, collections, bad debt and any call centre operating costs forecast as needed to serve OPDC customers.

The incremental Customer Care costs included in OPDC's residual cost to serve for years 1 through 10 was provided at page 3 of Exhibit I, Tab 1, Schedule 19 Attachment 2. In Year 10, Hydro One Forecast customer care OM&A is $876 thousand. The year 11 costs included in the Residual Cost to Serve can be derived by inflating the Year 10 forecast by 2%, resulting in $894 thousand.

All Hydro One's Customer Care costs are considered Shared Costs for the purpose of cost allocation and include the cost of all customer care services.

e) Yes.

# VECC INTERROGATORY # 24

**Reference:**

Exhibit A/Tab 5/Schedule 1, page 4 (lines 3-9)
EB-2017-0049, Exhibit G1/Tab 2/Schedule 1, pages 3-4

**Interrogatory:**

Preamble:
The Supplemental Evidence states: "Hydro One believes that the best way to ensure that OPDC customers are charged only their costs to serve is to introduce new rate classes for them".

In EB-2017-0049 Hydro One proposed: "For a small number of customers (i.e., USL, Street Lights, Sentinel Lights and Large Users), Hydro One proposes that they be merged into existing Hydro One rate classes".

a) Is Hydro One now proposing that there would be new separate rate classes for all of OPDC's existing customer classes, including its current USL, Street Lights, Sentinel Lights and Large Use classes?

**Response:**

a) No. Hydro One proposes that customers in the OPDC Street Light, Sentinel Light and USL classes be merged with Hydro One's equivalent classes, and that qualifying large use customers would be merged into Hydro One's ST class. See Exhibit I, Tab 1, Schedule8 for a description of the new rate classes being proposed for the remaining OPDC customers.

# VECC INTERROGATORY # 25

**Reference:**

Exhibit A/Tab 5/Schedule 1, page 5 (lines 13-16)
EB-2017-0049, VECC's Final Submissions

**Interrogatory:**

Preamble:

The Supplemental Evidence states: "Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the OPDC rate classes that will be less than what the cost-to-serve the OPDC customers would be if OPDC is not acquired." (emphasis added)

a) In Hydro One's view, is there any possibility that the cost allocation methodology used at the time of rebasing will result in an allocation of cost to customers that is more than what the cost-to-serve the OPDC customers would be if OPDC is not acquired"?

b) If Hydro One is of the view that there is no possibility of such a result, please explain why?

c) If Hydro One is of the view there is no possibility of such a result, please reconcile this view with the cost allocation results for acquired utilities in EB-2017-0049 where the allocated costs were higher (per VECC's Final Submissions, page 76) that the stand-alone costs to serve the acquired utilities.

**Response:**

a) Yes, there is always that possibility. However, given the amount of savings expected from the transaction and Hydro One's proposal for cost allocation and rate design in this application, Hydro One is confident that the customers of OPDC will benefit from this acquisition both in the short and long term. An estimate of the costs that would be allocated to the OPDC classes is provided in Exhibit I, Tab 1, Schedule 9, and shows that the estimated Year 11 costs allocated to OPDC customers would be $10.2, which is less than the status quo cost to serve of $14.4M.

b) Not applicable.

c) See part a) above.

# VECC INTERROGATORY # 26

**Reference:**
Exhibit A/Tab 5/Schedule 1, page 6 (lines 16-19)
EB-2017-0049

**Interrogatory:**
Preamble:
The Supplemental Evidence states: "This is effectively a direct allocation of locally-used fixed assets to OPDC customers. In other words, the adjustment factor ensures a more accurate reflection of the fixed assets, and associated costs, required to serve OPDC customers."

a) Does Hydro One accept that the OM&A costs attributed to the local assets used to serve OPDC customers using the cost allocation model will differ from the incremental OM&A costs related to the same assets as tracked by Hydro One?

b) Please provide a schedule that sets out: i) the 2021 Residual Costs to Serve associated with the acquired utilities in EB-2017-0049 and ii) based on the cost allocation proposed for the acquired utilities in EB-2017-0049, the equivalent OM&A costs allocated to the fixed local assets attributed to the acquired utilities via Hydro One cost allocation model for the same rate year?

**Response:**
a) Yes.

b) i) The incremental OM&A costs included in the Residual Cost for the three acquired utilities were $10.7M[1].

ii) The Table below provides the allocated OM&A costs attributed to the three acquired utilities, consistent with the values provided in EB-2017-0049, Exhibit Q, Tab 1, Schedule 1, Attachment 3 (O1 Sheet of the Cost Allocation Model (CAM)).

[1] EB-2017-0049, Exhibit A, Tab 3, Schedule 1, Page 7 – Table 2.

| Rate Class | "Direct" OM&A Costs | "Shared" OM&A Costs | Total Allocated OM&A Costs |
|---|---|---|---|
| AUR | $1.1 | $1.8 | $2.9 |
| AUGe | $0.2 | $0.3 | $0.5 |
| AUGd | $0.2 | $0.7 | $0.9 |
| AR | $3.9 | $4.9 | $8.8 |
| AGSe | $0.9 | $1.0 | $1.8 |
| AGSd | $0.8 | $0.7 | $1.4 |
| Combined Classes (i.e. St Lgt, Sent Lgt, USL and Woostock's GS>1,000kW)* | $0.3 | $0.3 | $0.6 |
| Total | $7.4 | $9.6 | $17.0 |

* Per Response to I-56-SEC-90, part (e), EB-2017-0049

The “Direct” OM&A shown in the Table are the amounts identified as “Distribution (di)” costs in the ‘O1’ sheet of the CAM. These values include the allocated OM&A costs associated with distribution fixed assets, which includes the cost of local fixed assets, as well as certain Shared Costs (e.g. OM&A associated with upstream and shared distribution facilities). The “Shared” OM&A costs shown in the table above are the amounts identified as “Customer Related Costs (cu)” and “General and Administration (ad)”in the ‘O1’ sheet of the CAM, and include some costs that are also part of the Residual Cost.

# VECC INTERROGATORY # 27

**Reference:**

Exhibit A/Tab 5/Schedule 1, pages 7-8

**Interrogatory:**

a) Based on EB-2017-0049, what were: i) the total costs allocated to the acquired utilities customers via Hydro One's cost allocation model and ii) the Residual costs attributed to the acquired utilities customers. Please include the relevant EB-2017-0049 references for the values provided.

b) Based on the ratio of these values please estimate the total allocated costs for OPDC customers in year 11 based on OPDC's forecast Residual Cost to Serve.

**Response:**

a) i) The total cost allocated to the acquired utilities customers via Hydro One's cost allocation model was $42.7M, as referenced in EB-2017-0049, Exhibit I, Tab 56, Schedule SEC 96 part e) iii). This amount includes $41.2M for the six acquired rate classes plus an estimated $1.5M for the combined rate classes (i.e. St Lgt, Sen Lgt, USL and Large Use).
ii) The Residual costs attributed to the acquired utilities customers were $25.6M as referenced in Exhibit I, Tab 56, Schedule SEC 96 part e) ii).

b) In Exhibit I, Tab 1, Schedule 9, Hydro One has produced a Cost Allocation Model (CAM) for year 11 (i.e. harmonization year). Based on the results of the CAM, the total allocated costs for OPDC in year 11 are $10.2M (refer to Exhibit I, Tab 1, Schedule 9, part (b)).

Given that a CAM run has been completed specific to OPDC, Hydro One does not believe the requested calculation using the ratio of the values from part a) is relevant. However, if calculated per the requested approach, the estimated total costs for OPDC based on the amounts shown in part a) would be $11.5M:

OPDC's year 11 residual costs = $6.9M
Ratio of Allocated costs/Residual Costs for the three acquired utilities (EB-2017-0049) = 42.7/25.6 = 1.67
OPDC's year 11 allocated costs = $6.9*1.67 = $11.5M

# VECC INTERROGATORY # 28

**Reference:**
Exhibit A/Tab 5/Schedule 1, page 8 (line 21) to page 9 (line 3)
Exhibit A/Tab 5/Schedule 1/Appendix A, page 8

**Interrogatory:**
Preamble:
The Supplemental Evidence states: Hydro One fully anticipates that it will be possible to set rates for the OPDC rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and OPDC customers. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is committing to charge OPDC customers no more than the higher goal post amount of $14.4 M and no less than their residual cost to serve of $7.9 M." (emphasis added)

a) In Hydro One's view, is there any possibility that it will not be able to set rates for the OPDC rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and OPDC customers? If not, please explain why.

b) Please confirm that if achieving both objectives is not possible then Hydro One would set the rates for OPDC customers such that the costs to be borne would not exceed $14.4 M (the forecast standalone cost to serve) – even if the R/C ratio results fell outside the Board's approved revenue to cost ranges. If not confirmed, how would Hydro One set the rates for OPDC customers in such circumstances?

c) Navigant's review and endorsement of Hydro One's rate design proposals appears to be predicated on Hydro One recognizing and adhering to the Board's approved revenue to cost ranges. Please reconcile this premise with the response to part (b).

**Response:**
a) While theoretically possible, the results of the cost allocation and rate design for the OPDC acquired classes provided in Exhibit I, Tab 1, Schedule 9, as well as Hydro One's experience with the proposed cost allocation and rate design of the Acquired Utilities in Hydro One's recent Distribution Application, indicate that this is a highly unlikely scenario.

b) Confirmed, however, Hydro One's proposal would be subject to OEB approval.

c) As indicated in the response to part a), the scenario is theoretically possible, but highly unlikely.

Navigant's review was premised on both criteria being satisfied – i.e., Hydro One's rate design process resulting in rates that: (i) fall within the Board's approved revenue-to-cost (R/C) ratio range (in existence at the time); and (ii) are able to recover revenues from OPDC customers that will be between the goal posts described in Exhibit A/4/1. Navigant was not asked to assess the highly unlikely scenario posited in VECC's question.

Hydro One believes that, in the highly unlikely case posited by VECC, the rate design objective of ensuring that neither Hydro One legacy or OPDC customers are harmed as a result of integrating OPDC into Hydro One's rate structure would justify a temporary departure from the Board's approved R/C ratio range. As noted in Exhibit I, Tab 6, Schedule 4, Hydro One believes that this would ensure that: (i) Hydro One legacy customers do not get *more* than the total savings available as a result of the OPDC acquisition; and (ii) OPDC customers' rates do not collect more than the revenue that would have been collected from them had they not been acquired.

The emphasis of Navigant's evidence is not that the specific OEB R/C ratio range is the only appropriate range, but rather that: (i) allowing a utility flexibility to deviate from a R/C of 1 is an appropriate response to the imprecisions of the cost allocation process and to balance competing rate design objectives; and (b) the Board has acknowledged this, and has altered its R/C ranges over time, based on the circumstances.

# VECC INTERROGATORY # 29

**Reference:**

Exhibit A/Tab 5/Schedule 1, pages 8-9

**Interrogatory:**

a) Please confirm that the rate design proposals set out on pages 8-9 (in particular the commitment to charge OPDC customers no more than the standalone cost to serve) only apply to the rebasing that will occur at the end of the 10-year deferral period and not to any subsequent rebasing applications.

b) If confirmed, what assurance does the Board and OPDC customers have that the no-harm test (per OPDC customers) will continue to be met in future rebasing applications?

**Response:**

a) In pages 8-9 of Exhibit A, Tab 5, Schedule 1, Hydro One describes its rate design proposal for the acquired customer classes. The first paragraph is Hydro One's standard process in determining rates for any of its customer classes, therefore if there is no change to OEB policies and procedures in rate design, Hydro One would expect that the principles articulated in this paragraph would be ongoing for subsequent rebasing applications.

   In the second paragraph, Hydro One confirms that the treatment with respect to the goal posts refers to the setting of rates at the time of the first rebasing.

b) The no-harm test applies at the time of the evaluation of the acquisition and it is premised upon the status quo. It is not realistic to continue to apply the no-harm test as a rate-setting feature 15-20 years into the future. There is also no basis for reliably establishing what the OPDC status quo costs would have been 16 years into the future and beyond. See Exhibit I, Tab 2, Schedule 24.

# VECC INTERROGATORY # 30

**Reference:**
Exhibit A/Tab 5/Schedule 1, pages 10-11

**Interrogatory:**
Preamble:
The Supplemental Evidence states: "In the Table 2 illustration, the cost allocation model has allocated $45 M to the acquired utility ($30 M in residual costs to serve plus $15 M in Shared Costs)".

a) In the illustrative example set out in Table 2, for those activities captured under Residual Costs, the cost allocation model is assumed to allocate costs equivalent to the Residual Costs (i.e., $30 M). Please confirm that this is simply an assumption made for purposes of the illustrative example and that, for those activities captured by the Residual Costs, the dollars allocated to the Acquired Utility by the cost allocation model could be more or less than the calculated Residual Costs. If not confirmed please explain why.

b) If confirmed, would it be reasonable to also include in the third row of Table 2 the impact of the cost allocation model treatment of Residual Costs and re-label the row – "Impact of Cost Allocation Model Treatment of Shared Costs and Residual Costs"?

c) Please confirm that the fourth row in Table 2 (Post-Consolidation Cost Allocation) is meant to reflect the cost allocation model results when applied to the consolidated utility. If not confirmed, please explain why.

d) Please confirm that the sixth row in Table 2 (Post-Consolidation Rates Revenue Requirement) is meant to reflect the results after the Status Quo Revenue Requirements for the Hydro One Legacy customers (collectively) and the Acquired Utility have been adjusted such that the R/C ratios for each class fall within the Board approved ranges. If not confirmed, please explain why.

e) Please confirm that the adjustment referred to part (d) is not an adjustment to the allocated costs as suggested by rows 4-6 in Table 2. Rather row 5 is really just the difference between the allocated costs and the revenue requirement after the adjustment referred in part (d) has been made. If not confirmed please explain why.

**Response:**

a) Confirmed, for illustrative purposes, the $30M cost assumption shown as Post-Consolidation Cost to Serve assumes that the Acquired Utility's residual cost to serve is equal to the dollars allocated in the cost allocation model. The dollars allocated to the Acquired Utility by the cost allocation model could be more or less than the $30M shown.

b) Confirmed, the third row does capture the combined impact of the cost allocation model treatment on Shared Costs and Residual Costs.

c) Confirmed.

d) Confirmed.

e) Confirmed. The adjustment referred to in row 5 is associated with setting the revenue to cost ratios for the rate classes and would impact the rates revenue requirement to be collected from customers.

# VECC INTERROGATORY # 31

**Reference:**
Exhibit A/Tab 5/Schedule 1, pages 10-12

**Interrogatory:**
Preamble: Assume the following cost allocation results at the time of rebasing:

| Illustrative Cost Allocation Exercise ($M) | | | |
|---|---|---|---|
| | Hydro One Legacy | Acquired Utility | Combined |
| Status Quo Revenue Requirement to be Collected from Customers | $1,000 | $40 | $1,040 |
| Post Consolidation Cost to Serve | $1,000 | $30 | $1,030 |
| Impact of Cost Allocation Model Treatment of Shared Costs | ($15) | $15 | - |
| Post-Consolidation Cost Allocation | $985 | $45 | $1,030 |
| Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement | $3 | ($3) | - |
| Post-Consolidation Rates Revenue Requirement based on Board Approved Ranges | $988 | $42 | $1,030 |
| Adjustment to Ensure No-Harm to Acquired Utility/Legacy Customers | $2 | ($2) | - |
| Post Consolidation Rates Revenue Requirement | $990 | $40 | $1,030 |
| Consolidation Benefits | ($10) | - | ($10) |

a) Hydro One Legacy is made up of a number of customer classes. Please explain how the initial adjustment to address the Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement would be allocated amongst Hydro One's Legacy customer classes (e.g., would it be allocated to just those Legacy customer classes with R./C ratios of less than 100%?).

b) How would Hydro One assign the subsequent adjustment required to Ensure No-Harm to Acquired Utility/Legacy Customers would be allocated amongst Hydro One's Legacy customer classes (i.e., would it be assigned to all Legacy customer classes or just to those with R/C ratios of less than 100%)?

c) If the response to part (b) is just those classes with R/C ratios below 100%, how can Hydro One ensure that all Legacy classes are actually benefitting from the acquisition?

d) If the response to part (b) is all customer classes, how can Hydro One ensure that the final R/C ratios will continue to all be within the Board's approved ranges?

**Response:**

a) Consistent with the approach previously approved by the Board for Hydro One when R/C ratio adjustments were required, Hydro One would propose that any R/C ratio adjustments would either shift costs to those rate classes whose R/C ratios are furthest below 100% or shift costs away from those classes whose R/C ratios are furthest above 100%.

b) See a).

c) Hydro One proposes to adjust R/C ratios as described in a), but is open to making any required R/C ratio adjustments in a manner that the Board deems most appropriate. Given that OPDC's rates harmonization will happen concurrent with the rebasing of all Hydro One rate classes, the resulting R/C ratios for all classes reflect both the allocation of Hydro One legacy costs plus the OPDC residual costs. As such, Hydro One believes that adjusting R/C ratios as described in part a) will minimize the cross subsidization between rate classes that is implicit in having a range of approved R/C ratios. The benefit to all Hydro One legacy classes is derived from the allocation of a portion of shared costs to the OPDC acquired rate classes a part of the cost allocation model.

d) As described in part a), to the extent that R/C ratios adjustments are required, none of the adjustments to legacy class R/C ratios will result in R/C ratios outside the Board approved range. Given the relatively small amount of revenues collected from OPDC acquired classes versus legacy classes, any adjustments required to the legacy R/C ratios to accommodate a shift in OPDC acquired class revenues would be small.

# CCC INTERROGATORY # 1

**Reference:**
A/T1/S1/p. 5

**Interrogatory:**
Please explain how Hydro One will fund the 1% reduction in rates for OPDC customers. Please explain how Hydro One will fund the $3.2 million "guaranteed ESM amount". Please explain how Hydro determined that $3.2 million was an appropriate amount to "guarantee" OPDC customers.

**Response:**
The 1% reduction in rates in years 1 to 5 of the rate deferral period will be funded through the synergy savings achieved as a result of the transaction and the deferred rebasing period.

The ESM guaranteed amount is the result of the forecast earnings that are expected in years 6 to 10 of the deferral period. Per the OEB's MAAD policies, Hydro One will share any over-earnings greater than 300 basis points 50/50 with ratepayers.

Hydro One has shown how it derived the $3.2M guaranteed ESM amount in Exhibit A, Tab 3, Schedule 1.

# CCC INTERROGATORY # 2

**Reference:**
A/T1/S1/p. 8

**Interrogatory:**
Please explain, in detail, how the transaction will, "ultimately create downward pressure on cost structures for both Hydro One and OPDC service areas." How will Hydro One demonstrate this to the OEB?

**Response:**
There have been multiple reports and studies that have promoted consolidation in the Ontario electricity distribution sector, most notably, the Ontario Distribution Sector Review Panel Report *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First* ("the Ontario Distribution Sector Review Panel Report").

The Ontario Distribution Sector Review Panel Report helped initiate and was discussed as part of the consultation of the OEB Staff Discussion Paper: *Review of the Board's Polices and Processes to Facilitate Electricity Distributor Efficiency: Service Area Amendments and Rate-Making Associated with Distributor Consolidation*[1]. The culmination of that consultation resulted in the current *Report of the Board on Rate-Making Associated with Distributor Consolidation.* CCC was a party to that consultation and therefore Hydro One assumes CCC has a copy of the Ontario Distribution Sector Review Panel Report.

This transaction achieves the savings and benefits contemplated by that report, e.g., the elimination of artificial electrical borders, reducing the burden on regulators and other administrative agencies, eliminating duplication of equipment, and creating a stronger LDC with the capacity to meet evolving customer needs. Further details pertaining to downward pressure on cost structures is documented in Exhibit A, Tab 2, Schedule 1.

[1] EB-2014-0138

# CCC INTERROGATORY # 3

**Reference:**
A/T5/S1/p. 1

**Interrogatory:**
In Year 11, when Hydro One plans to rebase how will it demonstrate to the OEB the following:

1. That the rates that collect costs from OPDC customers are less than what those customers would have paid in the absence of the proposed transaction;

2. That the Hydro One legacy customers are left unharmed, or slightly better off than they would have been in the absence of the proposed transaction.

**Response:**
1) In response to Part 1 of this question, please see the response to Exhibit I, Tab 6, Schedule 12.

2) In response to Part 2 of this question, the fact that the Hydro One legacy customers are left unharmed, or slightly better off than they would have been in the absence of the proposed transaction, will be demonstrated by the extent to which the revenue to be collected from OPDC customers exceed the Residual Cost added to Hydro One's revenue requirement that is associated with serving the OPDC customers. Any costs collected from OPDC customers in excess of the $6.9M Residual Cost represent a reduction in the Shared Costs that would need to be recovered from Hydro One legacy customers in the absence of the transaction.

# CCC INTERROGATORY # 4

**Reference:**
A/T5/S1/p. 1

**Interrogatory:**
Please explain how "consolidation of the distribution sector has and will continue to result in beneficial outcomes for all customers – both for the customers of the acquired utilities and Hydro One's legacy customers". Specifically, how have Hydro One's legacy customers benefitted from consolidation?

**Response:**
Hydro One's MAAD Application commits to charging OPDC customers no more than the higher goal post amount of $14.4M[1]. Under this scenario, $7.9M in synergy and efficiency cost savings would accrue to the benefit of Hydro One's legacy customers and OPDC customers would not be harmed as they would still be paying no more than the status quo. If the initial results from the cost allocation and rate design process results in total costs in excess of $14.4M being borne by OPDC customers, this would mean that Hydro One's other customers would be getting *more than* $7.9M in costs savings. In that situation Hydro One would propose a reduction in revenue-to-cost ratios for the OPDC customer classes such that the costs to be borne by OPDC customer classes would not exceed $14.4M. While a reduction to the revenue-to-cost ratios for the OPDC customer classes would shift some costs to be collected to other Hydro One classes, this would simply reduce the benefit that is accruing to Hydro One's other classes to the maximum value of $7.9M.

[1] Exhibt A, Tab 4. Schedule 1, Page 9 of 13 –April 26, 2019

# CCC INTERROGATORY # 5

**Reference:**
A/T4/S1/p.2

**Interrogatory:**
Hydro One has calculated OPDC "Status Quo" revenue requirement for year 11. Please specifically outline all of the assumptions used to derive these numbers.
The evidence states that the OPDC rate base is forecast to increase from the 2010 OEB approved amount of $20.8 million to $53.7 million by 2030. Please explain how these numbers were derived.

**Response:**
For clarification, the OPDC Status Quo forecast for Year 11 revenue requirement was produced by OPDC, and not Hydro One as the question implies. Specific assumptions used to forecast the status quo OPDC revenue requirement are provided in Attachment 20 to the prefiled evidence.

OPDC's Status Quo rate base forecast for Year 11 uses the OPDC Status Quo capital expenditures from Table 1 of Exhibit A, Tab 1, Schedule 1, up to Year 10, along with the detailed assumptions provided in Attachment 20 to the prefiled evidence. To forecast Year 11 rate base, OPDC Year 10 Status Quo capital expenditures are increased by 2% and added to the previous year, as described in Attachment 20 to the prefiled evidence. Table 2 of the same exhibit indicates that LV Charges must be included to compare the cost to service under the "status quo" with the "residual" cost to serve. An explanation of how the LV Charges were estimated is provided in Exhibit I, Tab 3, Schedule 9.

The Year 11 Residual and Status Quo rate base and revenue requirement forecasts are provided in Attachment 18 to the prefiled evidence, as provided via a Blue Page update on April 26, 2019.

Attachment 18 provides OPDC's forecast Status Quo rate base for 2019 of $37.7M. This is an increase of $16.9M (or 81%) in the ten years since OPDC's last rebasing in 2010. During the subsequent 11 years, OPDC's service territory rate base would increase from $37.7M (2019) to $52.9M (Hydro One's Residual scenario - 2030), an increase of

$15.2M (or 40%), per Hydro One capital forecast provided in Exhibit A, Tab 2, Schedule 1.

# CCC INTERROGATORY # 6

**Reference:**
A/T4/S1/p. 2

**Interrogatory:**
Please provide the most current Distribution System Plan for OPDC. If the transaction is completed how does Hydro One incorporate that plan into its overall DSP? How will the OPDC customers be assured that the capital needs in their service territory are appropriately prioritized?

**Response:**
OPDC has not completed a Distribution System Plan. In light of the pending acquisition of OPDC by Hydro One, OPDC has deferred the completion and filing of a cost of service rate application as well as the Distribution System Plan (DSP). Until such time as a decision was rendered on the MAAD application, it was felt that the time and significant costs to prepare these documents would result in undue costs to customers.

Once OPDC is integrated, Hydro One will manage the assets of OPDC as it does for the rest of its distribution service territory. Capital needs for all Hydro One will be prioritized using the existing Hydro One Asset Risk Assessment process. Capital investments will go to the assets with the greatest need or to those that pose the greatest risk to the system. Initially, Hydro One will track OPDC assets and capital spending in an Appendix to its main DSP for the Orillia area. After the deferral period, the LDC assets will be combined with Hydro One.

# CCC INTERROGATORY # 7

**Reference:**
A/T4/S1/p. 8

**Interrogatory:**
Is Hydro One prepared, at this time, to commit to setting rates for the OPDC rate zone based on the "Total Residual Cost to Serve" upon rebasing?

**Response:**
As Hydro One indicated in Exhibit A, Tab 5, Schedule 1, page 11, Hydro One believes that the savings from consolidation should benefit both legacy and acquired customers. If Hydro One was to set rates for OPDC customers based on the "Total Residual Cost to Serve" then Hydro One's legacy customers would not see any of the benefits of consolidation. Hydro One is not proposing this outcome; however, if the Board did decide that OPDC customers should only be charged their residual cost to serve, Hydro One's legacy customers would not be harmed (i.e., 100% of the benefits of the transaction would accrue to OPDC customers), as they would not incur any additional costs as a result of the transaction.

# CCC INTERROGATORY # 8

**Reference:**
A/T4/S1/p. 11

**Interrogatory:**
Please explain how Hydro One and OPDC estimated that if the sale is not approved distribution rates will increase by an annual average rate of 2-4% over the 10-year deferral period. Please include all assumptions.

**Response:**
For clarification, OPDC provided the forecast estimates for annual increases over the 10-year deferral period should the sale not be approved, and not Hydro One as the question implies.

Please refer to Exhibit I, Tab 2, Schedule 17 for details of the components driving the annual OPDC Status Quo revenue requirement on a year by year basis from Year 1 (2020) to Year 11 (2030), and the calculation of the average annual revenue requirement increase over that period.

The assumptions underpinning the OPDC Status Quo forecast are provided in detail at Attachment 20 to the prefiled evidence.

# CCC INTERROGATORY # 9

**Reference:**
A/T4/S1/p. 9

**Interrogatory:**
Please explain, in detail, how Hydro One will track and report on the actual incremental OM&A and capital costs to serve OPDC customers. Please specifically define what is meant by "incremental' OM&A and capital costs. Please describe, in detail, the format in which these costs will be reported to the OEB.

**Response:**
Please see Exhibit I, Tab 1, Schedule 7 part a) for information regarding how Hydro One will track actual incremental OM&A and capital costs to serve OPDC during the deferral period.

Please see Exhibit I, Tab 1, Schedule 7 for a definition of "incremental" costs.

Hydro One plans to report the actual incremental OM&A and capital costs to serve OPDC by work program at the time of the next rebasing. This would be similar to that provided in EB-2017-0049 Exhibit I, Tab 53, Schedule CCC-70.

# CCC INTERROGATORY # 10

**Reference:**
A/T5/S1/p. 3

**Interrogatory:**
Is it Hydro One's current proposal that all acquired customers will have their own rate classes? Does this mean that the rates will never be harmonized with the other Hydro One rate classes?

**Response:**
Please see the response to Exhibit I, Tab 1, Schedule 8 part a).

# CCC INTERROGATORY # 11

**Reference:**
A/T5/S1

**Interrogatory:**
How will rates for the Seasonal Rate Customers in the OPDC rate zone be determined going forward, if they are now Hydro One customers, and subject to Hydro One's Seasonal Rate Customer definitions?

**Response:**
During the deferred rebasing period Hydro One and OPDC rate tariffs will be maintained separately and so Hydro One's Seasonal Rate customer definition will not apply to OPDC customers. At the time of rate harmonization, Hydro One proposes to create a separate new acquired rate class that will include all residential customers in the OPDC service area and therefore the Hydro One Seasonal customer definition will not apply to the new rate class.

# CCC INTERROGATORY # 12

**Reference:**
A/T5/S1/p. 4, 7

**Interrogatory:**
The evidence states that Hydro One proposes to allocate shared costs to OPDC's rate classes by applying the same cost allocation principles and allocators normally used in the OEB's cost allocation model to allocate such costs. When shared costs are allocated to OPDC's rate classes upon rebasing, how will Hydro One ensure, that rates payable by both OPDC customers and Hydro One legacy customers are lower (or at least not greater) than they would be otherwise.

**Response:**
Hydro One's proposal for cost allocation and rate design, as described in Exhibit A, Tab 5, Schedule 1, will ensure that costs to be collected from OPDC customers are less than what those customers would have paid in the absence of the proposed transaction. This will be demonstrated by comparing the revenue to be collected from OPDC customers at proposed Year 11 rates, versus OPDC's Year 11 status quo revenue requirement. Exhibit I, Tab 1, Schedule 11 illustrates how this could translate into OPDC customers' total bills.

# CCC INTERROGATORY # 13

**Reference:**
N/A

**Interrogatory:**
How will the implementation of Bill 87, Fixing the Hydro Mess Act, 2019 potentially impact Hydro One's proposals for setting rates for the OPDC rate zone during the deferred rebasing year.

**Response:**
The implementation of Bill 87 does not impact Hydro One's proposals for setting rates for OPDC customers at this time. It is not possible to say whether Bill 87, or any new legislation, will exist at the end of the 10 year deferred rebasing period that could impact Hydro One's rebasing application and harmonization proposals at that time.

# CCC INTERROGATORY # 14

**Reference:**
A/T5/S1/p. 9

**Interrogatory:**
Please provide the Terms of Reference for the Navigant Consulting Ltd. Engagement. What was the cost of the study and how was it funded?

**Response:**
Please see Exhibit I, Tab 3, Schedule 15. The cost will be funded through synergy savings during the deferral period.

# CCC INTERROGATORY # 15

**Reference:**
N/A

**Interrogatory:**
Please provide copies of all correspondence between Hydro One and OPDC regarding the Supplemental Evidence. Please provide copies of all correspondence between Hydro One and the Corporation of the City of Orillia regarding the Supplemental Evidence. When did the Corporation of the City of Orillia approve the transaction as it is currently structured? Did the City explicitly approve Hydro One's current proposals to maintain separate rate classes for OPDC's customers? If not, why not? When did Hydro One's Board of Directors last review and approve the transaction?

**Response:**
The approval resolution was passed at the meeting of the Board of Directors of Hydro One Inc. held on August 12, 2016. A copy is provided in Attachment 6 to the prefiled evidence.

Hydro One declines to provide the requested information as it is information not relevant to the relief sought in the Application. In support of this position, Hydro One relies on the Handbook. One of the objectives of the Handbook is stated at Page 1:

> *"The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. In order to facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.*
>
> *Recent OEB policies and decisions on consolidation applications have already established a number of principles to create a more predictable regulatory environment for applications. This Handbook will provide further clarity to applicants, investors, shareholders and other stakeholders."*

Regulatory efficiencies in consolidation proceedings cannot be achieved if the evidentiary record is allowed to include information that pertains to matters outside of the OEB's stated considerations.

At page 3 of the Handbook, the OEB states that the Filing Requirements found in Schedule 2 set out the information needed for inclusion in an application. The scope of review to be carried out during a consolidation proceeding is discussed at page 9 of the Handbook. There, the Handbook states that "*the question for the OEB is neither the why nor the how of the proposed transaction. The application of the "no harm test" is limited to the effect of the proposed transaction…*" Deliberations, activities, and documents leading up to the final transaction agreement are not matters relevant for consideration on an application made pursuant to section 86(2) of the OEB Act.

The requested information concerns deliberations, activities and documents leading up to the final transaction agreement and in the course of preparing this Application, as amended. As such, and based on the above reasons, Hydro One respectfully submits that the requested information is not relevant to this proceeding and therefore declines to produce these materials.

# CCC INTERROGATORY # 16

**Reference:**
N/A

**Interrogatory:**
Please indicate whether the Share Purchase Agreement between the City, OPC and Hydro One Inc., dated August 15, 2019, is still in place. If no, please file the most updated Agreement.

**Response:**
Hydro One notes that the Share Purchase Agreement, filed as Attachment 5 to the prefiled evidence, was dated August 15, 2016. A subsequent Amending Agreement, also filed as Attachment 5 to the prefiled evidence, is dated September 26, 2018.

See Exhibit, I, Tab 5, Schedule 2.

# CCC INTERROGATORY # 17

**Reference:**
N/A

**Interrogatory:**
Please provide a schedule setting out OPDC's proposed rates for the each year of the deferral period, given Hydro One's proposal to reduce Base Delivery Rates by 1% and the apply a price cap for years 6-10.

**Response:**
The table below provides the requested information:

| Year | | % Annual Change | Residential | | General Service < 50 kW | | General Service > 50 kW | |
|---|---|---|---|---|---|---|---|---|
| | | | Fixed ($/month) | Volumetric ($/kWh) | Fixed ($/month) | Volumetric ($/kWh) | Fixed ($/month) | Volumetric ($/kW) |
| 2019 | Current | | $27.93 | $0.0000 | $37.42 | $0.0165 | $340.60 | $3.5825 |
| 2020 | Year 1 | -1.0% | $27.65 | $0.0000 | $37.05 | $0.0163 | $337.19 | $3.5467 |
| 2021 | Year 2 | 0.0% | $27.65 | $0.0000 | $37.05 | $0.0163 | $337.19 | $3.5467 |
| 2022 | Year 3 | 0.0% | $27.65 | $0.0000 | $37.05 | $0.0163 | $337.19 | $3.5467 |
| 2023 | Year 4 | 0.0% | $27.65 | $0.0000 | $37.05 | $0.0163 | $337.19 | $3.5467 |
| 2024 | Year 5 | 0.0% | $27.65 | $0.0000 | $37.05 | $0.0163 | $337.19 | $3.5467 |
| 2025 | Year 6 | 2.7% | $28.40 | $0.0000 | $38.05 | $0.0167 | $346.29 | $3.6425 |
| 2026 | Year 7 | 1.7% | $28.88 | $0.0000 | $38.70 | $0.0170 | $352.18 | $3.7044 |
| 2027 | Year 8 | 1.7% | $29.37 | $0.0000 | $39.36 | $0.0173 | $358.17 | $3.7674 |
| 2028 | Year 9 | 1.7% | $29.87 | $0.0000 | $40.03 | $0.0176 | $364.26 | $3.8314 |
| 2029 | Year 10 | 1.7% | $30.38 | $0.0000 | $40.71 | $0.0179 | $370.45 | $3.8965 |

# CCC INTERROGATORY # 18

**Reference:**
N/A

**Interrogatory:**
If significant capital requirements arise in the OPDC rate zone during the deferral period, how will those investments be funded?

**Response:**

If capital expenditure requirements incurred during the deferral period qualified under the OEB's Incremental Capital Module (ICM) rate-setting mechanism, then Hydro One would apply for an ICM as discussed in the *Handbook to Electricity Distributor and Transmitter Consolidations*, page 17. OPDC customers would be responsible for paying the ICM rate rider.

If the expenditures did not quality for an ICM, then those capital requirements would be funded by Hydro One's shareholder up to the time of rebasing of rates and approval of the expenditures in rate base.