ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998 c.15 (Schedule B), s. 78.

AND IN THE MATTER OF an application by Hydro One Networks Inc. to raise its electricity distribution rates effective January 1, 2018 and continuing each year for another 4 years, until December 31, 2022.

EB-2017-0049

CROSS-EXAMINATION COMPENDIUM

PANEL 3

ANWAATIN INC.

June 18, 2018

TAB 1

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Frank D'Andrea
Vice President
Regulatory Affairs

BY COURIER

June 15, 2018

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-2017-0049 - Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application") Settlement Proposal regarding Hydro One Transmission/ Anwaatin Motion to Review and Vary (EB-2016-0160 / EB-2017-0335)

Please find enclosed the Settlement Proposal between Hydro One and Anwaatin Inc. regarding EB-2017-0335 Anwaatin Inc.'s Motion to Review and Vary the Ontario Energy Board Decision in EB-2016-0160.

The Settlement Proposal was provided during the Oral Hearing on June 15th, 2018 and was entered into the evidentiary record as Exhibit K4.4.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

SETTLEMENT PROPOSAL

ANWAATIN INC.

Motion to Review and Vary the Ontario Energy Board's Decision
on Hydro One Network Inc.'s Transmission Rates in EB-2016-0160

EB-2017-0335

June 15, 2018

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Anwaatin Inc.
EB-2017-0335

SETTLEMENT PROPOSAL

A. PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board (the "**OEB"**) in connection with the Anwaatin Inc. ("**Anwaatin"**) Motion to Review and Vary the Ontario Energy Board's Decision on Hydro One Networks Inc.'s ("**HONI"**) Transmission Rates in EB-2016-0160 (the "**Decision"**) through the EB-2017-0335 proceeding (the "**Anwaatin MRV"**). It follows settlement discussions that took place after the Anwaatin MRV was argued and before the OEB rendered a decision in the Anwaatin MRV. The settlement discussions were predominantly between Anwaatin and HONI, with limited involvement of a distributed energy resource developer, Abundant Solar Inc. ("**Abundant"**), and the two intervenors in the Anwaatin MRV, (Schools Energy Coalition "**SEC**") and Vulnerable Energy Consumers Coalition "**VECC**") in a manner that was guided by the process contemplated in the OEB''s Practice Direction on Settlement Conferences, as amended (the "**Practice Direction**"). OEB staff were also informed of the settlement discussions, but in accordance with the Practice Direction OEB Staff is neither a Party nor a signatory to this Settlement Proposal. Nonetheless, OEB Staff who were apprised of the developments in and around the settlement discussions are bound by the same confidentiality provisions that apply to all of the above-mentioned Parties and entities. The communities Anwaatin represents for the Anwaatin MRV and this Settlement Proposal ("**the Anwaatin First Nations**") include Aroland First Nation, MoCreebec Eeyoud, and Waaskiinaysay Ziibi Inc. Development Corporation ("**WZI**"), an economic development corporation representing five First Nations in the Lake Nipigon watershed: Animbiigoo Zaagiigan Anishinaabek, Bingwi Neyaashi Anishinaabek, Biinjitiwaabik Zaaging Anishinaabek. Red Rock Indian Band, and Whitesand First Nation.

This Settlement Proposal is subject to the following conditions subsequent:

(i) Acceptance of the Settlement Proposal by the OEB in its entirety, and in a manner that allows for implementation of its terms;

(ii) The Pilot Project satisfies the OEB and Ministry of Energy's Impact Assessment Requirements:

   a. System Impact Assessment conducted by the IESO; and

   b. Connection Impact Assessment conducted by HONI.

(iii) Obtaining any approvals required by Abundant and Anwaatin/Anwaatin First Nations, if any, regarding the repurposing of existing FIT contracts if included or required to facilitate reliability as part of the Pilot Project.

(iv) Decisions made by HONI to proceed with Phase 1 and 2 investments as described in Paragraph 1.5(c) below.

(collectively, the "**Conditions Subsequent**").

Unless amended on the written consent of Anwaatin and HONI, all Conditions Subsequent must be fulfilled by no later than December 31, 2021, failing which this Settlement Proposal is null and void and of no further effect.

In entering this agreement, the Parties understand and agree that, pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "Act") the OEB has the exclusive initial jurisdiction with respect to the interpretation and enforcement of the terms hereof.

B. DESCRIPTION OF SETTLEMENT

1.1 The Parties

Anwaatin and HONI were the central parties to the Anwaatin MRV and are the signatories to this Settlement ("**Parties**"). Two other interveners participated in the Anwaatin MRV in a limited manner. SEC intervened in the Anwaatin MRV for the limited purpose of requesting that any cost consequences to the Decision be reviewed. VECC intervened in the Anwaatin MRV in support of Anwaatin. Abundant was involved in the settlement discussions in order to ensure that the proposed solutions were technically feasible and able to be implemented in a timely manner.

1.2 Confidentiality

The Parties agree that the settlement discussions shall be subject to the rules relating to confidentiality and privilege contained in the Practice Direction. The Parties acknowledge that confidentiality in that context does not have the same meaning as confidentiality in the OEB's Practice Direction on Confidential Filings, and the rules of that latter document do not apply. The Parties interpret the Practice Direction to mean that the documents and other information provided, the discussion of each issue, any offers and counter-offers, and the negotiations leading to settlement of each issue during the course of the settlement discussions are strictly confidential between the Parties and were undertaken on a without prejudice basis. None of the foregoing settlement discussions and processes leading to this Settlement Proposal are admissible as evidence in this or any other proceeding, or otherwise, except where the filing of such settlement information is necessary to implement the Settlement Proposal and/or resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal and subject to the direction of the OEB. In such case, only the settlement information that is necessary for the purpose of implementing and interpreting the settlement proposal shall be filed and such information shall be filed using the appropriate protections afforded under the relevant legislation and OEB instruments. These obligations shall not impede the filing of this Settlement Proposal itself or its use as evidence in subsequent proceedings including, without limitation, the EB-2017-0049 proceeding.

Further, the Parties have a positive and ongoing obligation not to disclose settlement information to persons who were not involved in the settlement discussions.

1.3 Parameters of Proposed Settlement

All of the elements of this Settlement Proposal have been settled by the Parties as a package, and none of the provisions of this Settlement Proposal are severable. Numerous compromises were made by Anwaatin and HONI with respect to various matters to arrive at this Settlement Proposal. The distinct issues and elements addressed in this Settlement Proposal are inextricably interrelated, and changes in the agreed parameters are likely to have consequences in other areas of this Settlement Proposal, which may be unacceptable to one or more of the Parties. If the OEB does not accept this package in its entirety, then there is no settlement (unless HONI and Anwaatin agree in writing that any portion of the package that the OEB does accept may continue as part of a valid Settlement Proposal).

If the OEB directs the Parties to make reasonable efforts to revise the Settlement Proposal, the Parties agree to use reasonable efforts to discuss any potential revisions, but neither Anwaatin nor HONI will be obligated to accept any proposed revision. The Parties agree that Anwaatin and HONI must agree with any revised Settlement Proposal prior to its re-filing with the OEB.

None of the Parties can withdraw from this Settlement Proposal except in accordance with the terms contemplated herein (including satisfaction of the Conditions Subsequent) and with Rule 30.05 of the OEB's Rules of Practice and Procedure.

1.4 Full Settlement of Parties

a) HONI will undertake a pilot project that is intended to explore the feasibility of implementing non-wires distributed energy projects (**"Pilot Project")** in and around the Anwaatin First Nations communities as a means to improve reliability in remote and radial areas of HONI's system. The Pilot Project is intended to provide HONI with an opportunity to assess whether similar and repeatable approaches may be used in other remote areas of its system that are experiencing poor reliability conditions.

b) HONI's investment in the Pilot Project shall not exceed $5 million and shall be funded from HONI's distribution capital investment plan.

c) Anwaaatin and HONI agree to work together in an effort to offset or augment this investment amount by obtaining government funding through subsidies or grant programs.

d) The Parties acknowledge that any further funding of this initiative is dependent on (i) the feasibility of the Pilot Project and (ii) further review and approval by the OEB to increase HONI's approved capital investment envelope and recovery through rates of the additional funding requirements.

e) Anwaatin/Anwaatin First Nations communities and Abundant plan to jointly develop and implement up to 45 MW of FIT contracted solar generation in the following repurposed locations:

   a. Longlac M2/Nakina DS: maximum size 5 MW
   b. Moosonee: maximum size 10 MW
   c. Longlac M1/Longlac East DS: maximum size 9 MW
   d. Longlac TS LV bus: maximum size 10 MW
   e. Beardmore DS: maximum size 1.1 MW
   f. Jellicoe DS: maximum size 0.9 MW
   g. Red Rock: maximum size 9 MW.

f) HONI will consider the technical feasibility of having Abundant/Anwaatin First Nation solar generation be used as a source of supply to the energy storage facilities as part of the Pilot Project.

g) HONI commits to processing all connection impact assessment applications made by Anwaatin/Anwaatin First Nations and Abundant in a timely manner, taking into account all other existing connection impact assessment applications HONI has received.

h) The first phase of the Project will complete the technical assessment of energy storage facilities that may improve reliability in the communities served by HONI's F2 Feeder that serves the Nakina area. Energy storage facilities for Phase 1 are targeted to be in-service by March 31, 2019.

i) The design, size and load to be served by Phase 1 facilities are matters not yet determined and will be dependent upon further technical review. HONI will continue to regularly consult with Anwaatin regarding the status of the Phase 1 design.

j) A technical review of Phase 1 implementation is targeted for completion within six months of in-service timing. This information is intended to be used to inform the approaches, design, and viability of Phase 2.

k) During the EB-2017-0049 proceeding, Anwaatin and HONI will provide the OEB with an update on the Project, including any preliminary information regarding sizing of energy storage, siting alternatives and preliminary cost estimates. As part of this update, Anwaatin and HONI may file this Settlement Proposal.

l) The Project shall have no retrospective financial or cost consequences that will require revisiting the amounts assessed and determined by the Board in the EB-2016-0160 Decision.

m) Anwaatin and HONI will consult and cooperate on any other longer-term wires and/or non-wires electricity reliability proposals and solutions affecting the Anwaatin First Nations communities and may jointly pursue other projects intended to improve reliability in other regions served by HONI.

1.5 Description of Project

(a) **Phase 1** is focussed on improving reliability to the communities served by HONI's F2 Feeder situated in the Nakina region. The objective is to provide measurable improvement to the reliability of supply to these communities and as compared to the five-year historical average SAIDI and SAIFI values applicable to these communities. Anwaatin/Anwaatin First Nations, Abundant and HONI intend to achieve this objective through designing and implementing energy storage facilities in close proximity to the referenced communities and the option of having solar generation used to recharge the storage facilities in times of outages.

Anwaatin/Anwaatin First Nations, Abundant and HONI will take reasonable steps to find suitable off-reserve locations in proximity to HONI's feeder distribution facilities to site both solar generation and energy storage facilities at locations in close proximity to local community distribution load.

All constructed Phase 1 energy storage facilities will initially be owned and operated by HONI. HONI agrees to explore in good faith the possibility of Anwaatin First Nations obtaining a minority, non-operating ownership interest in the Phase 1 facilities, should the said facilities proceed to development. The valuation of this interest will be based on HONI's actual investment cost incurred to the date that such interest is acquired by Anwaatin First Nations.

HONI's design of the Phase 1 energy storage facilities will take into account, among other technical factors, historic load levels in the Aroland community. Anwaatin agrees to work with HONI in assessing ways to prioritize distribution service during times of an outage so that stored energy may be used for essential services in the communities.

HONI will consult with Anwaatin/Anwaatin First Nations and Abundant regarding design and sizing of the energy storage facilities.

Anwaatin/Anwaatin First Nations and Abundant intend to jointly develop and implement solar generation facilities in close proximity to all identified energy storage facilities so that the solar generation facilities may be used to supply the energy storage facilities at times when outages occur in the Aroland community.

The targeted timelines for Phase 1 are as follows:

- Scope of work completed and storage partner selected by July 15, 2018
- Siting locations determined and community engagement completed by July 31, 2018
- Completion of all detailed engineering and financial viability review completed by September 30, 2018
- Civil work completed by November 30, 2018

- In-service of energy storage facilities by March 31, 2019.

Anwaatin/Anwaatin First Nations and Abundant acknowledge that targeted timelines may require adjustments, given acquisition timing of requisite land rights, remoteness of worksite locations, workforce availability and the season in which construction work occurs.

(b) **Phase 2:** is focussed on Waaskiinaysay Ziibi Inc. (an economic development corporation representing Rocky Bay First Nation, Bingwi Neyaashi Anishinaabek, Red Rock Indian Band, Whitesand First Nation, and Animbiigoo Zaagiigan Anishinaabek and other smaller First Nations along HONI's A4L transmission line) (collectively, **"WZI"**).

The Phase 2 objective is complete technical assessments of potential non-wires solutions for WZI communities in order to determine whether cost-effective and technically feasible ways may be used through the use of non-wires solutions to improve reliability to levels consistent with HONI's current average SAIDI and SAIFI metrics for its northern rural distribution customers and by deploying similar approaches and measures described in Phase 1. The results of Phase 1 are intended to inform and be used in the technical assessments contemplated for Phase 2.

In Phase 2, HONI and Anwaatin will also work together to identify and evaluate critical loads in MoCreebec Eeyoud locations served by HONI's F1 and F3 feeders and assess whether cost effective and technically feasible non wire energy storage facilities could be implemented to significantly improve reliability for identified critical loads.

Anwaatin will facilitate meetings between HONI, Abundant, WZI and other smaller interested First Nations served by the A4L line in order to describe, explain, and assess solar/storage reliability solutions.

HONI's Phase 2 commitments are limited to preparing technical assessments that consider deployment of energy storage facilities in the WZI communities in the same manner as carried out for Phase 1 and which technical assessments have been filed as part of Exhibit I-6-1(c) in OEB Hearing EB-2017-0049.

Once the technical assessments for Phase 2 are completed, HONI and Anwaatin/Anwaatin First Nations, Abundant and WZI will meet and discuss all technical, operational and financial viability issues that would need to be addressed before any further steps are taken to initiate potential investments. This discussion is intended to explore possible joint development opportunities to implement energy storage and solar generation facilities so that they may be used in an effective and feasible way to provide a means of back-up supply in times of outages for small communities along the A4L route, while maintaining feeder integrity.

(c) **Final Decisions to Proceed with Phase 1 Investments.** HONI's decision to proceed with the work execution and installation of Phase 1 is subject to: (1) investment requirements to not exceed the amounts or outcomes described in paragraph 1.4(b)-(d) above, (2) HONI's technical review and its acceptability to HONI of the final design of the facilities, (3) the level of reliability improvement expected from Phase 1 is reasonably achievable as determined by HONI, and (4) Phase 1 facilities are expected to provide a repeatable outcome for development in other areas of HONI's system. HONI will consult with Anwaatin on the ongoing status of these conditions throughout Phase 1.

1.6 Other Matters

(a) **Ongoing HONI Communications with the Anwaatin First Nations Communities.** HONI and Anwaatin agree to develop and implement a communications plan to facilitate regular communications between them and the First Nations communities to discuss and assess the progress and success of the Pilot Project.

(b) **Pilot for Future HONI/Indigenous Community Cooperation.** If the Pilot Project is successful, HONI and Anwaatin agree to work together and promote the Pilot Project as a potential reliabilty solution in other Indigenous and similarily situated communities.

(c) **Conditions Precedent.** The final form of the Settlement Proposal is subject to the approval of the Band Councils and/or the applicable First Nation governing body(ies).

(d) **Conditions Subsequent.** This Settlement Proposal is subject to the Conditions Subsequent listed in Part A (Preamble) above.

ACCEPTED AND AGREED TO THIS 15 DAY OF JUNE 2018

Ferio Pugliese, Executive Vice President Customer Care and Corporate Relations Hydro One Networks Inc.	Larry Sault, President and Chief Executive Office Anwaatin Inc.

TAB 2

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Frank D'Andrea
Vice President
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BY COURIER

June 15, 2018

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-2017-0049 - Interrogatory Response Update in Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application")

Please find enclosed the updated interrogatory I-06-Anwaatin-001 for Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application. This update takes into account a new pilot project initiative that Hydro One is evaluating in the area that serves Anwaaatin communities.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Enc.

Anwaatin Inc. Interrogatory # 1

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

A-04
A-04-02

Preamble:

Hydro One's distribution business serves the majority of the First Nations and Métis communities in Ontario.

In the Application, Hydro One states that it will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities (increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work).

Hydro One indicates that, through its First Nations and Métis Strategy (Exhibit A, Tab 4, Schedule 2), communities would like to see an increase in procurement, investment/ownership opportunities, and other business partnership opportunities for Aboriginal businesses. Hydro One further indicates that First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in Northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.

Hydro One also notes that First Nations communities and customers feel they are disproportionately impacted by high electricity costs. Many have raised concerns that their delivery charge is higher than their electricity consumption. In addition, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive.

Hydro One indicates that it hopes to address many of the Indigenous concerns with reliability and distributed energy resources, including Indigenous investment and ownership, and is developing a consolidated framework to guide First Nations and Métis relations and engagement across all lines of business.

Interrogatory:

a) Please describe how Hydro One consulted First Nations on any and all investment/ownership opportunities and other business partnership opportunities related to DERs in grid-connected communities, and what resulted from these consultation efforts.

b) Please describe in detail and provide all reports, notes, memos and documents related to:

   i. all processes Hydro One undertook to consult with Indigenous communities on this distribution rate application; and
   ii. the outcome of those consultations.

c) Please list each and all distributed energy resources that:

   i. Hydro One considered for Indigenous communities;
   ii. Hydro One consulted with First Nations on;
   iii. Hydro One implemented or intends to implement for Indigenous communities;
   iv. the Hydro One actions that result from them; and
   v. the quantified improvements in reliability and service that result from them.

d) Since First Nations in Ontario have now acquired or will soon acquire more than 14 million shares of Hydro One (representing 2.4% of the outstanding common shares of Hydro One), please describe how Hydro One will address the significant concerns of Indigenous shareholders relating to the high frequency and duration of power outages in Indigenous communities and the disparate reliability afforded to this class of shareholder.

Response:

a) Hydro One engages First Nations on investment/ownership opportunities on a project by project basis such as the Bruce to Milton Transmission Project and the Niagara Reinforcement Project. At this time, Hydro One has not yet engaged First Nations on any investment/ownership opportunities and other business partnership opportunities related to distributed energy resources (DERs) in grid-connected communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

b)

i) Hydro One regularly engages with First Nations and Métis communities about various issues of concern.

As part of its review of customer needs and preferences, Hydro One conducted a telephone survey in August 2016 of a random and representative sample of 300 First Nations customers. A key finding was that First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. A copy of the telephone survey results with First Nations customers can be found EB-2017-0049, Exhibit B1-1-1, Section 1.3, Attachment 1, pages 1562 to 1570.

In addition, Hydro One also held engagement sessions with (a) the 88 First Nation communities it serves on February 9 and 10, 2017, the session reports for which are provided as Attachment 4 to section 1.3 of the DSP (Exhibit B1, Tab 1, Schedule 1) and (b) the 29 Métis Councils represented by the Métis Nation of Ontario on May 13, 2017. The purpose of the sessions was to engage on Application as well as to share information on various programs and initiatives benefiting Indigenous communities and to hear about issues and concerns expressed by participants as they related to Hydro One. Please find enclosed reports, presentations, and notes related to these engagement sessions as Attachments 1 to 9.

Hydro One will be hosting a second First Nations Engagement Session on February 21, 2018 which will be open to representatives of the 88 First Nations communities it serves. A similar engagement session will be offered to the Métis Nation of Ontario in 2018.

ii) For the most part, Hydro One had existing initiatives in place to address the concerns raised in these engagement sessions. Hydro One made 35 specific commitments at the

February 9 and 10, 2017 First Nation engagement session and 95% of these commitments were addressed throughout the year. Hydro One made 10 specific commitments at the May 13, 2017 engagement session with the Métis Nation of Ontario. Attachment 10 lists the 10 questions asked by the Métis Nation of Ontario and includes Hydro One responses.

The outcomes of these engagement sessions was the development of additional strategies and plans responsive to the key issues and concerns expressed by participants as they related to the transmission and distribution system.

To improve affordability, Hydro One implemented an outreach plan to ensure all eligible First Nation customers benefit from the First Nations Delivery Credit announced as part of the Ontario Fair Hydro Plan and which came into effect on July 1, 2017. Hydro One also adjusted a plan to implement the First Nations Conservation Program (FNCP) in new First Nation communities in 2018. The FNCP is a follow-up program to the Aboriginal Conservation Program which was implemented by the Independent Electricity System Operator (IESO) and ended in 2015 after providing services to 39 communities. The FNCP is designed to serve the communities not served by the IESO's earlier program**.**

In addition, Hydro One also implemented the Get Local Initiative to help customers by providing information about conservation programs and resources that may assist low-income customers and ensuring that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program. Finally, in 2018 Hydro One started to roll-out the Affordability Fund to improve First Nations' home energy efficiency by providing free energy-saving upgrades, which can lower home energy use and, correspondingly, a customer's electricity bill over the long term.

In order to improve reliability and in response to complaints raised at the engagement sessions, Hydro One has revised its vegetation management policy whereby it will increase the frequency of forestry maintenance work on reserve. In addition, on measures to improve reliability, please see parts c) i), ii), and iii) of Exhibit I-6-Anwaatin-2.

On liability and access, Hydro One responded to feed-back committing to notify or seek permission as applicable from First Nation communities when conducting reconnection work on reserve in the context of its distribution business.

c) In its February 12, 2018 response to Exhibit I-6-Anwaatin-001 c), Hydro One stated that it had not yet considered distributed energy resources related to Indigenous communities. Hydro One has recently begun exploring opportunities to partner with interested First Nation communities and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

By way of update, in April 2018, Hydro One commenced preliminary discussions with Anwaatin regarding renewable sourced generation interconnection capacity and energy storage capacity at distribution station locations in proximity to Anwaatin communities. These discussions have evolved into assessing whether an energy storage pilot project could be developed in a remote region of the distribution system serving Anwaatin communities and tested to determine reliability improvement and whether this approach could be used as a repeatable approach in other regions of the system.

More technical information is now available regarding this initiative. Hydro One's current technical assessment has focused on the three distribution feeder lines that serve the Nakina and Moosonee communities (referred to as Moosonee F1 and F3, and Nakina F2).

These assessments, included in Attachment 11, provide information regarding the following:

- the historical reliability of these feeders;
- three potential energy storage solutions that are in the process of evaluation;
- expected levels of costs of each solution; and
- the potential reliability improvement.

The assessments are continuing. Completion of all detailed engineering and financial viability review is targeted by September 30, 2018. Forecast investment for this new pilot project will not exceed $5 million. Government grants and funding may also provide a source of funds. One of the key objectives with this pilot project is assessing scalability to meet similar reliability concerns in other communities served by Hydro One.

At this time, issues affecting pilot project feasibility include, but are not limited to, the following:

- Installation of energy storage facilities on a radial line will result in the "islanding" of an area, with the consequence that during the outage, this load would be served by non-wires storage. This technical design and approach are not found on any other part of the Hydro One Distribution system and will require careful operational scrutiny.

- Estimated capital costs set out in the attached technical assessments are preliminary and subject to further review. Investment estimates depend on a variety of factors, including battery sizing, variability of load, and availability of government funding programs.

- Cost/benefit analysis of the potential reliability improvement must also be considered by a comparison to other potential ways to improve reliability, such as changes in vegetation management and prior transmission investments that have been made in the area.

d) Hydro One will continue to invest in its assets according to asset condition assessments without regard to preferences of specific shareholders.

Hydro One and First Nations Engagement Session

February 9th & 10th, 2017

Disclaimers

In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or any other entity contained in this presentation are intended only to illustrate past performance of such entitles and are not necessarily indicative of future performance of Hydro One. In this presentation, “Hydro One” refers to Hydro One Limited and its subsidiaries and other investments, taken together as a whole.

Forward-Looking Information

This presentation contains “forward-looking information” within the meaning of applicable Canadian securities laws. Forward-looking information in this presentation is based on current expectations, estimates, forecasts and projections about Hydro One’s business and the industry in which Hydro One operates and includes beliefs of and assumptions made by management. Such statements include, but are not limited to: statements related to project costs; statements related to continued consolidation of the electric utility market; statements related to dividends, including expectations regarding the ability of continued rate base expansion through capital investments to drive growth in dividends; statements regarding future equity issuances; expectations regarding funding for planned capital investments; statements related to rate applications and models; statements regarding rate base and cash flows; and statements regarding productivity improvements.

Words such as “aim”, “could”, “would”, “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “target”, and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Hydro One does not intend, and it disclaims any obligation to update any forward-looking information, except as required by law.

The forward-looking information in this presentation is based on a variety of factors and assumptions, as described in the financial statements and management’s discussion and analysis. Actual results may differ materially from those predicted by such forward-looking information. While Hydro One does not know what impact any of these differences may have, Hydro One’s business, results of operations and financial condition may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking information are described in the financial statements and management’s discussion and analysis.

Non-GAAP Measures

Hydro One prepares and presents its financial statements in accordance with U.S. GAAP. “Funds from Operations” or “FFO” and “Adjusted Earnings Per Share” are not recognized measures under U.S. GAAP and do not have standardized meanings prescribed by U.S. GAAP. These are therefore unlikely to be comparable to similar measures presented by other companies. Funds from Operations should not be considered in isolation nor as a substitute for analysis of Hydro One’s financial information reported under U.S. GAAP. “Funds from Operations” or “FFO” is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) non-controlling interest distributions. Management believes that these measures will be helpful as a supplemental measure of the Company’s operating cash flows and earnings. For more information, see “Non-GAAP Measures” in Hydro One’s 2016 full year MD&A.

Thursday, February 9th 2017 - Agenda

Hydro One and First Nations Engagement Session
Thursday, February 9, 2017
8:30 a.m. - 4:30 p.m.

Session Objectives: We would like to come together to share mutual aspirations and hear from you about the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board

Item	Speaker	Start Time	Duration
Welcome • Introduction to Today's Session • Introduction of First Nations' Elder (Andrew Wesley) • Prayer from Elder	Phil Goulais & Elder	8:30am	30 mins
Introductory Remarks • Hydro One's Commitment to First Nations (including recent success stories)	Mayo Schmidt	9:00am	30 mins
Individual Introductions • Introduction of each Chief or Delegate • Open Discussion "What would you like to get out of today's session?"	Phil Goulais	9:30am	60 mins
BREAK		**10:30am**	**15 mins**
Customer Service • Customer Vision, Strategy, & Key Initiatives • Faciliated Dialogue: Exercise at each table. "What does great Customer Service mean to you"	Ferio Pugliese	10:45am	90 mins
NETWORKING LUNCH		**12:15pm**	**45 mins**
Distribution Rate Filing (2018-2022) • Key Findings from Customer Consultation • Revenue Requirement and Distribution Rate Profile • Cost Allocation Methodology, Rate Design	Oded Hubert & Henry Andre	1:00pm	90 mins
BREAK		**2:30pm**	**15 mins**
System Investments • Education about why the power goes out • Reliability statistics on FN communities (either a few sample communities or in aggregiate) • Investments in the Dx Rate Filing which will help to improve reliability (i.e. worst feeder)	Greg Kiraly	2:45pm	60 mins
Wrap Up • Feedback • Protocol for Future Discussions	Phil Goulais	3:45pm	30 mins

Friday, Feb 10th 2017 - Agenda

Hydro One and First Nations Engagement Session
Friday February 10, 2017
8:30 a.m. - 4:30 p.m.

Session Objectives: We would like to come together to share mutual aspirations and hear from you about the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board

Item	Speaker	Start Time	Duration
Welcome • Introduction to Today's Session • Introduction of First Nations' Elder (Andrew Wesley) • Prayer from Elder	Phil Goulais & Elder	8:30am	30 mins
Individual Introductions • Introduction of each Chief or Delegate • Open Discussion "What would you like to get out of today's session?"	Phil Goulais	9:00am	60 mins
BREAK		**10:00am**	**15 mins**
Customer Service • Customer Vision, Strategy, & Key Initiatives • Faciliated Dialogue: Exercise at each table. "What does great Customer Service mean to you"	Ferio Pugliese	10:15am	60 mins
CEO Remarks • Hydro One's Commitment to First Nations (including recent success stories)	Mayo Schmidt	11:30am	30 mins
NETWORKING LUNCH		**12:00pm**	**30 mins**
System Investments • Education about why the power goes out • Reliability statistics on FN communities (either a few sample communities or in aggregiate) • Investments in the Dx Rate Filing which will help to improve reliability (i.e. worst feeder)	Greg Kiraly	2:45pm	60 mins
BREAK		**2:30pm**	**15 mins**
Distribution Rate Filing (2018-2022) • Key Findings from Customer Consultation • Revenue Requirement and Distribution Rate Profile • Cost Allocation Methodology, Rate Design	Oded Hubert & Henry Andre	1:00pm	90 mins
Wrap Up • Feedback • Protocol for Future Discussions	Phil Goulais	3:45pm	30 mins

CUSTOMER SERVICE

Ferio Pugliese

Executive Vice President, Customer Care and Corporate Affairs

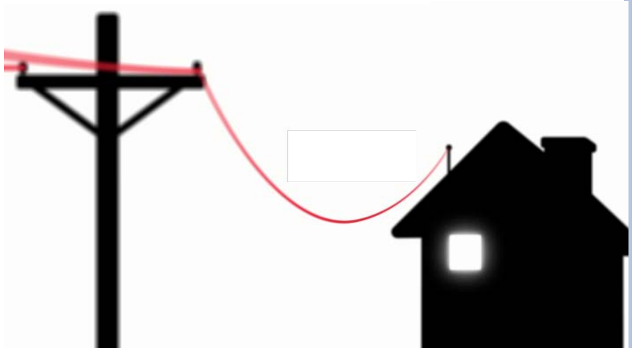
Hydro One and First Nations Engagement Session

February 9 and 10, 2017

5

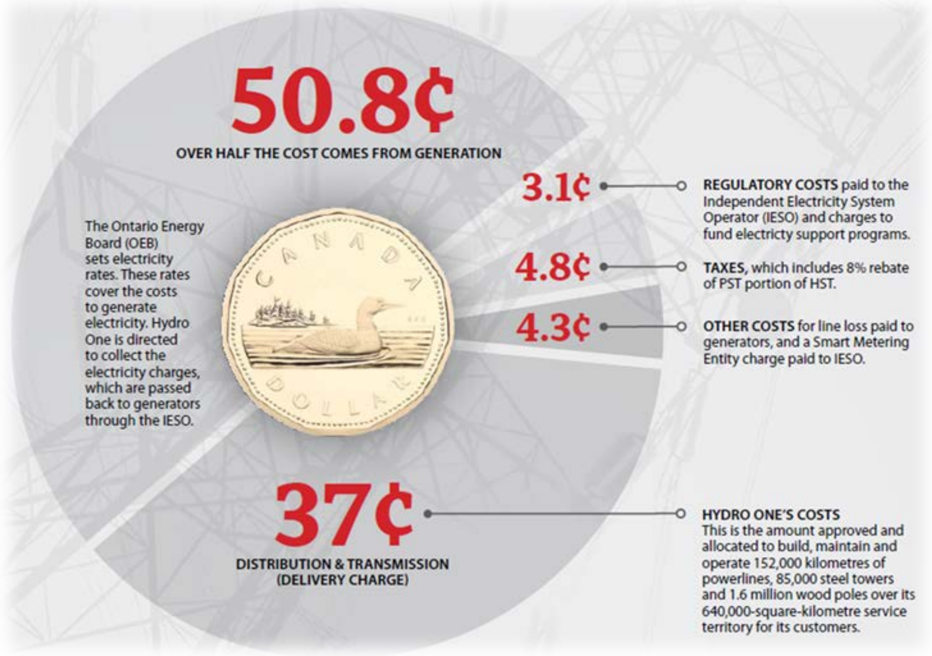
Customer Service Vision

- We are easy to do business with
- We are there when customers need us
- We are always connected



We Are Easy To Do Business With

- Education
- Advocacy
- Responsiveness



We Are There When Customers Need Us

- Local presence
- First Nations Engagement
- Responding in ways you prefer

In-Community Sessions

Face-to-Face Interactions

Province-Wide

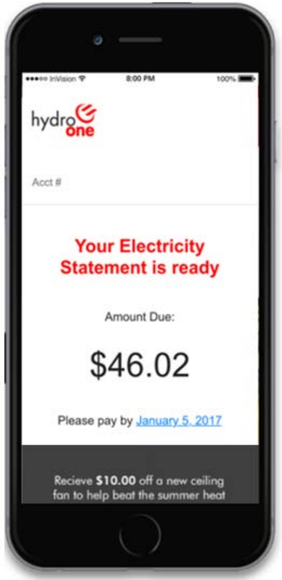
Program Enrollment

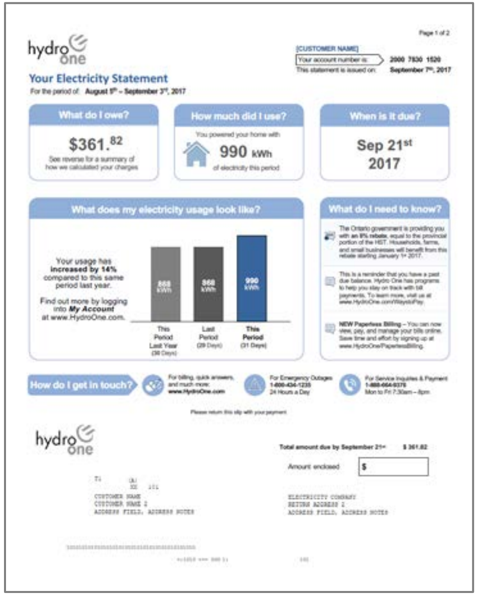
We Are Always Connected

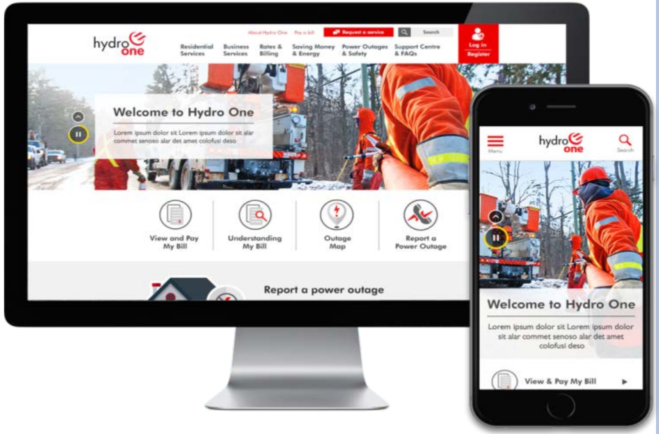
eBill Notifications & High Usage Alerts

New Website

Redesigned Bill







Our Commitment to You

Be present where we can

Listen and advocate on your behalf

Partner and respond

First Nations Reliability Performance Overview

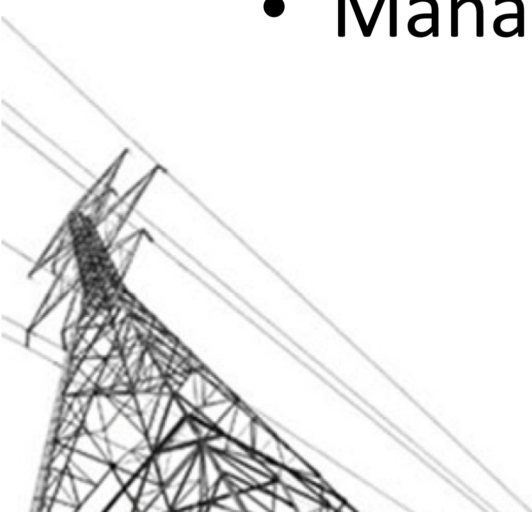
Greg Kiraly and Mike Penstone

Hydro One and First Nations Engagement Session

February 9 & 10, 2017

Today’s Presentation

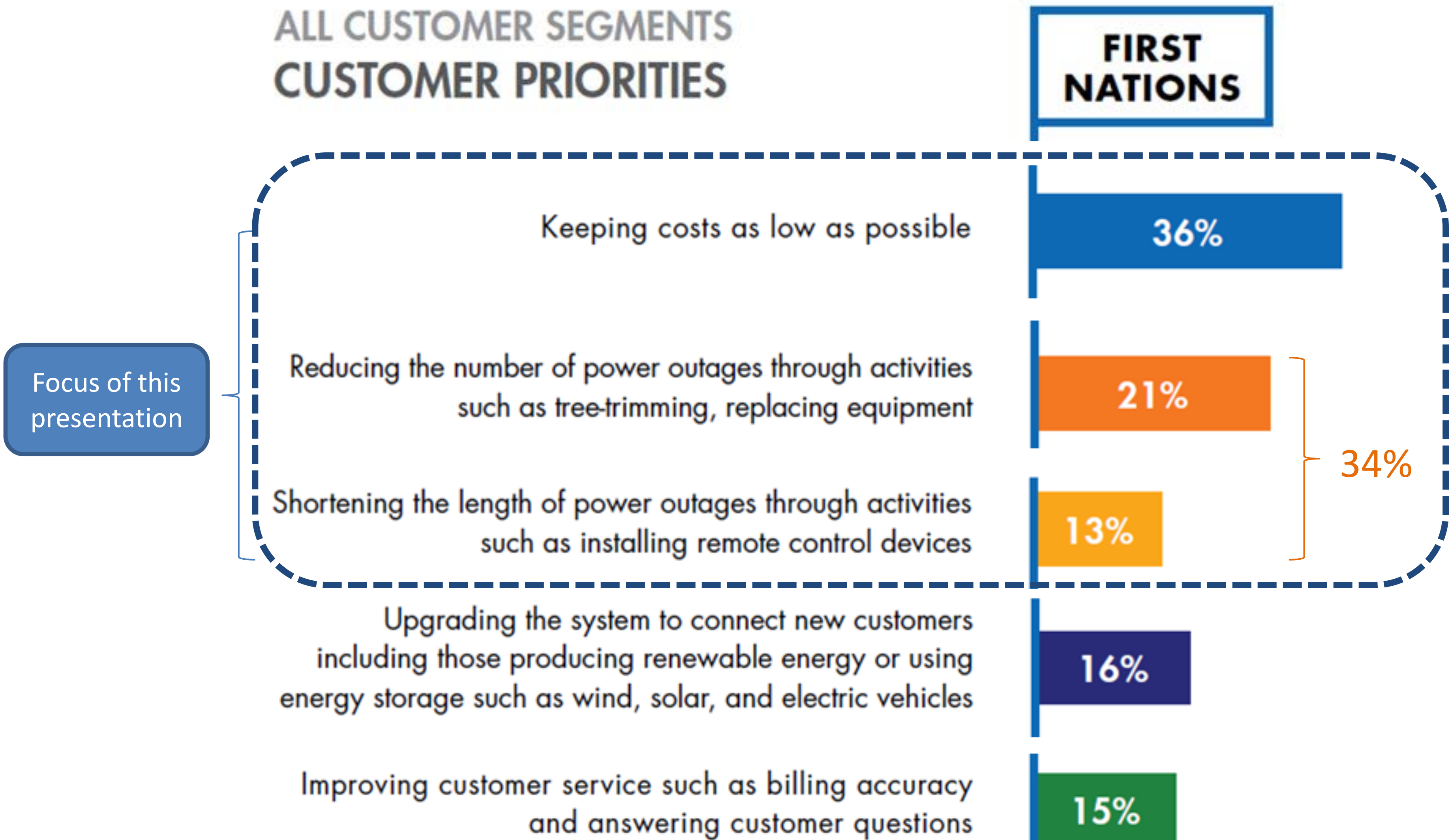
- Customer Engagement Initiative
- Reliability to First Nations Communities
- Managing Costs



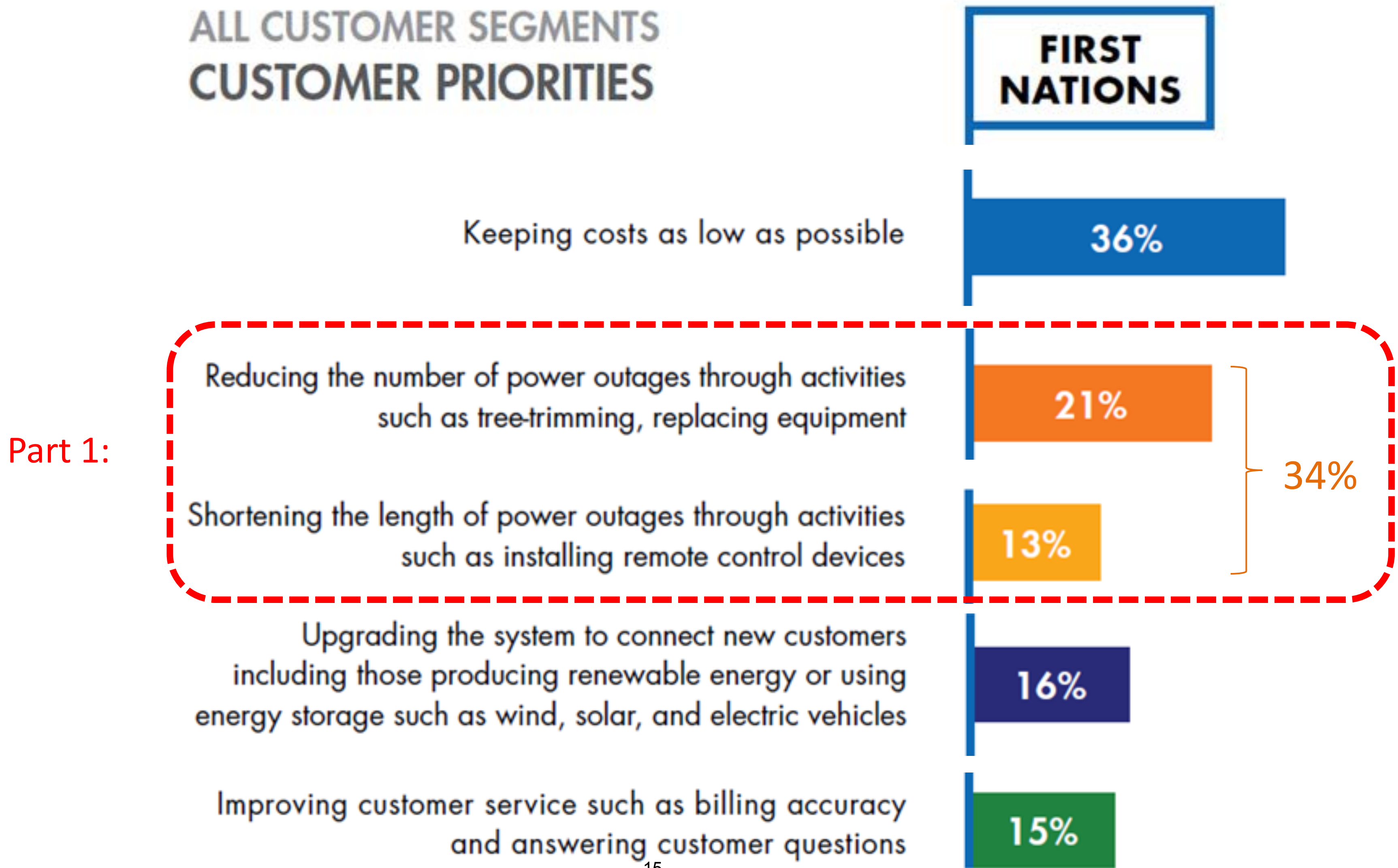
Customer Engagement Initiative

- Occurred in Q2 2016
- A 3rd party facilitated the initiative
- Input received from 300 First Nations Customers

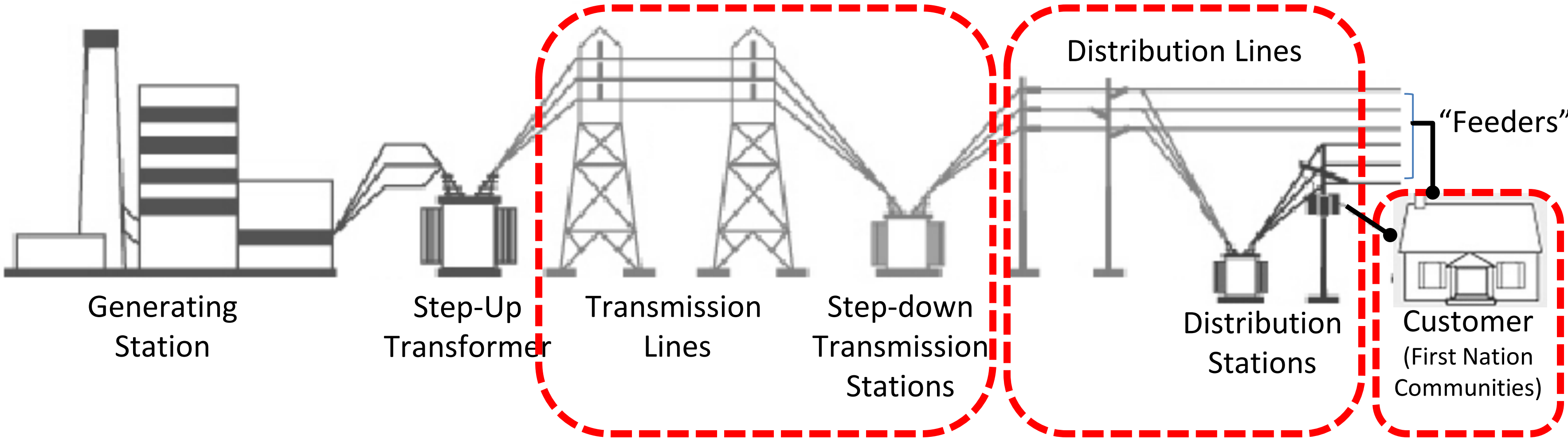
Customer Engagement Results



Customer Engagement Results



Generation → Customer

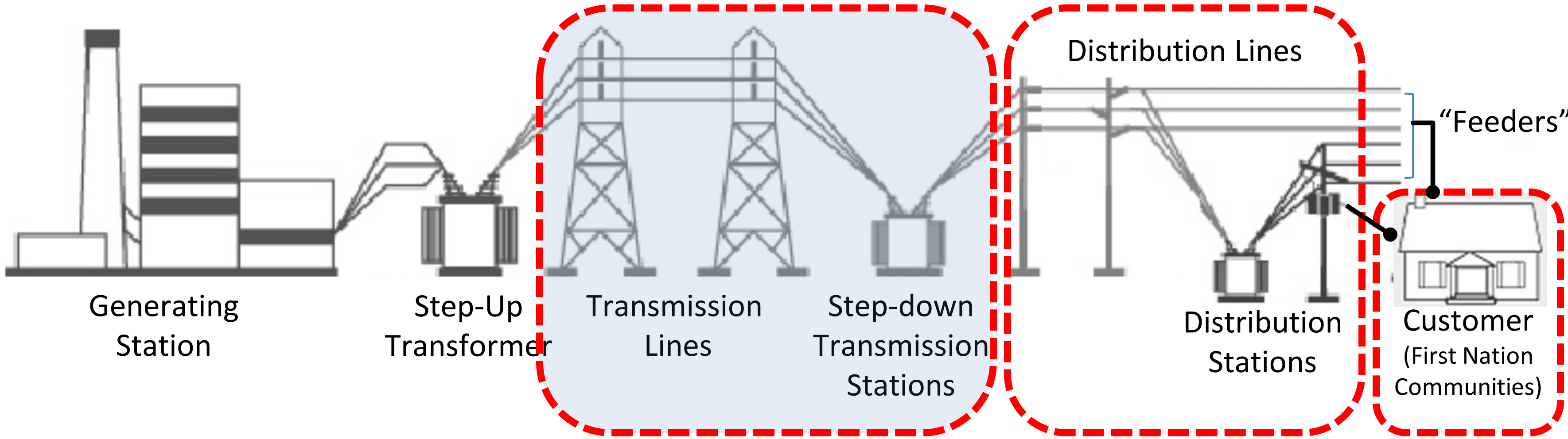


1 **Transmission System:** ~490 Transmission Lines, ~340 Transmission Stations, 29,000 km of Transmission Lines

2 **Distribution System:** ~3200 Distribution Lines, ~1000 Distribution Stations, 130,000 km of Distribution Lines

3 **First Nation Communities:** Supplied from 55 Transmission Lines and from 89 Distribution Lines

Transmission System



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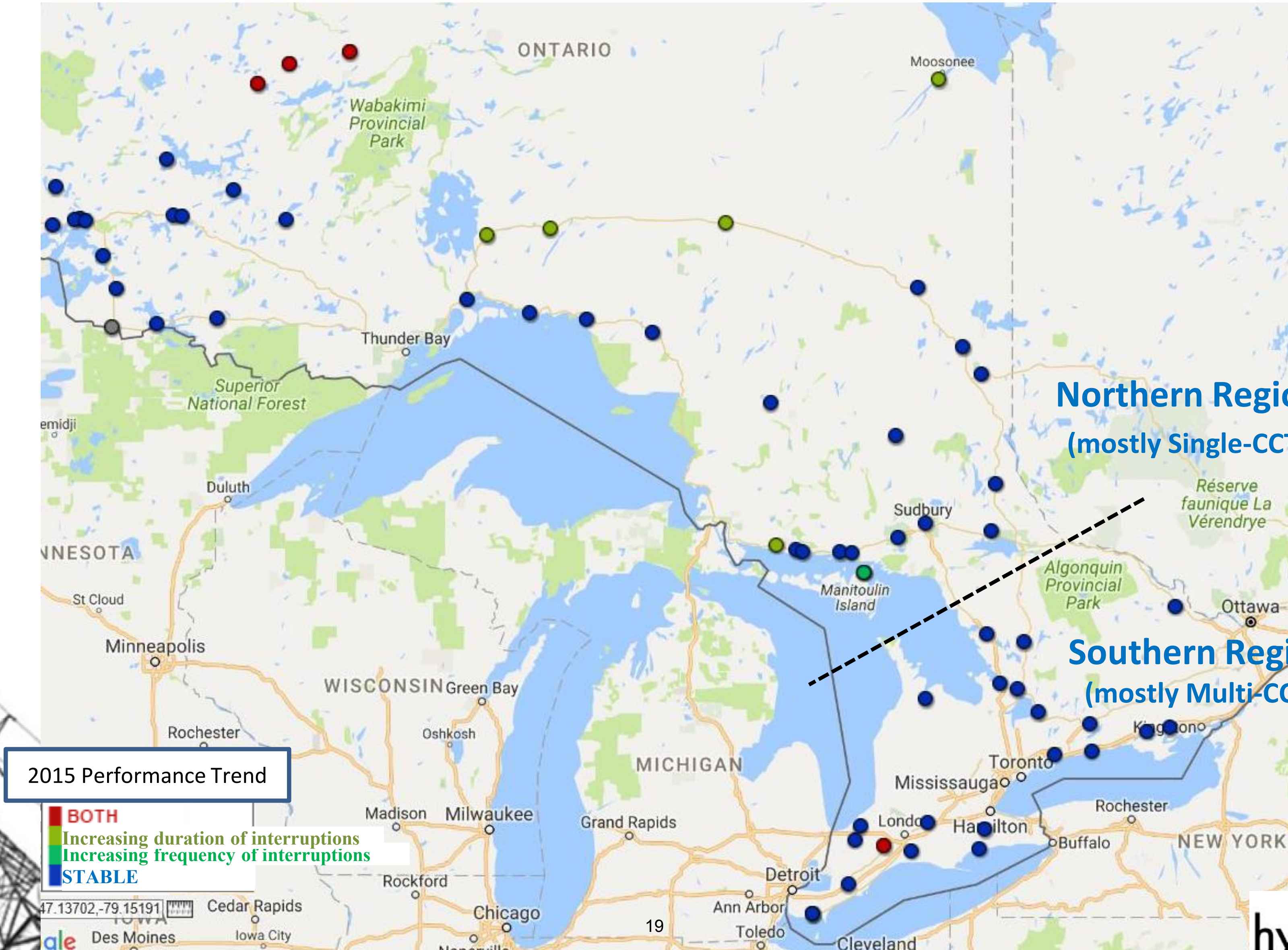
Tx System – Primary Causes of Interruptions:
(~67% occurs from Weather & Equipment Failures)

Power outage causes (2012-2016)

Equipment failure	**49%**	Majority of failures have occurred on Lines assets (Insulators, Wood Poles, Conductor, etc)
Weather	**18%**	Adverse weather (freezing rain, ice, lightning)
Environment	**15%**	Occasionally, Hydro One experiences tornados, forest fires, major environmental events
Animal/vehicle or Tree Contacts	**14%**	Animal contacts with Hydro One's equipment and off-corridor tree-felling events
Configuration	**2%**	Issues relating to the configuration of the system at the time of the event.
Unconfirmed causes	**1%**	Sometimes Hydro One crews can't determine the exact cause of an outage.

First Nations: Transmission Connections



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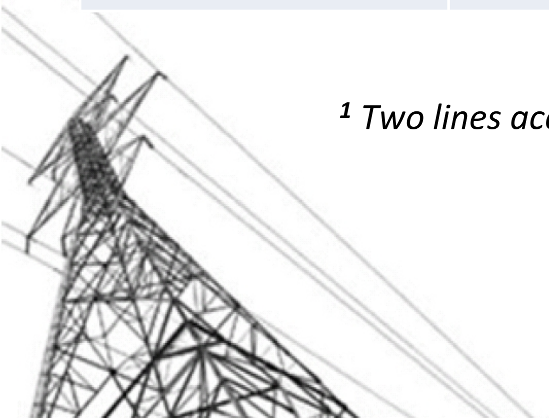
Transmission Connections Performance: By Geographic Region (First Nations Only)

Transmission System - Northern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes/ Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
[1]First Nations	44	216.4 (68.4)	4.48

Transmission System - Southern Sub-System (2016 YE Performance)			
Tx Reliability Index	# of Transmission Connections	Duration of Interruptions (interruption minutes /Tx Connection)	Frequency of Interruptions (# of interruptions /Tx Connection)
First Nations	25	25.1	1.20

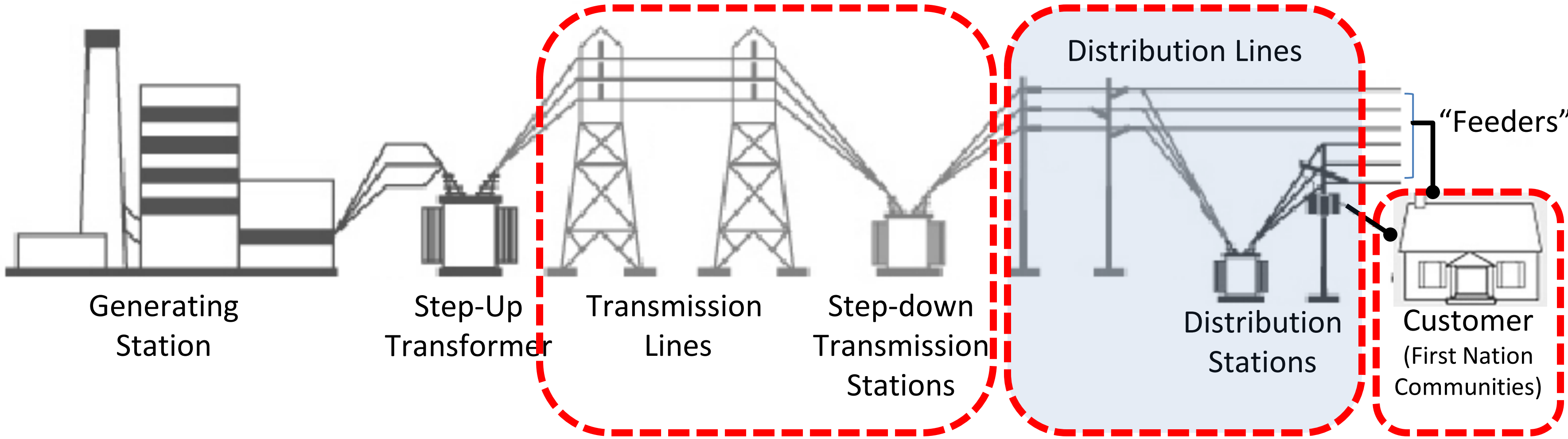


[1] *Two lines account for 58% of total interruption minutes for entire year*

How is Hydro One maintaining Reliability in the Transmission System?

- **Increasing Capital Investments (Lines)**
- **Leveraging Technology (Distance-to-Fault)**
- **Reducing Planned Outages (Bundling Work)**

Distribution System



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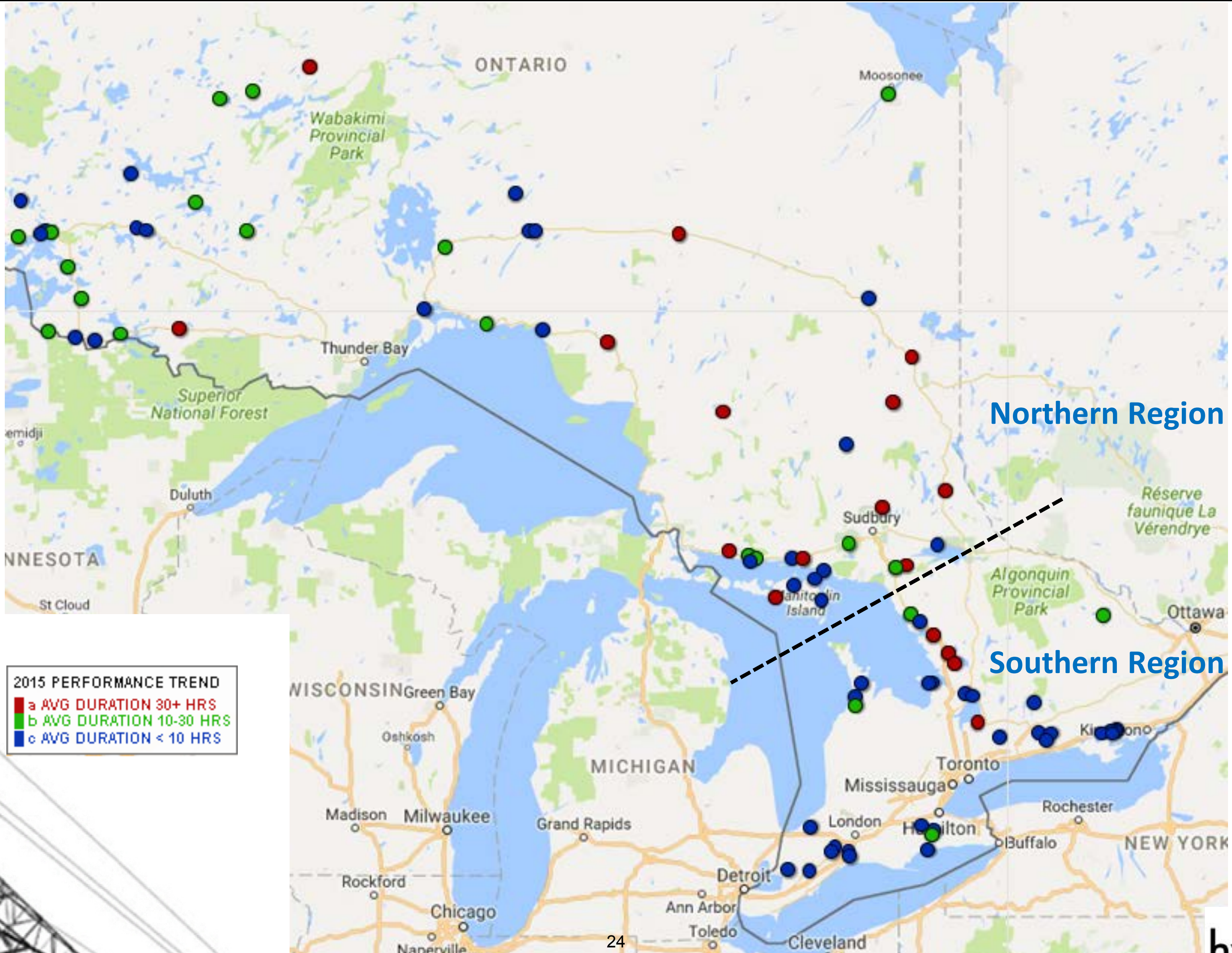
Dx System – Primary Causes of Interruptions:
(~50% occurs from Tree Contacts & Equipment Failures)

Power outage causes (2013-2015)

Tree damage	**24%**	Trees fall on lines during storms.
Equipment failure	**24%**	Poles, transformers, lines failures can cause an outage.
Unconfirmed causes	**19%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Scheduled outages	**16%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Transmission Outage	**12%**	Issues relating to the larger grid, like damage to transmission lines.
Animal or vehicle damage to equipment	**5%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.

First Nations: Distribution Connections



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Dx Performance: By Customer Segmentation (& First Nations Only)

Distribution System - Overall (2016 YE Performance)

Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	13.3	3.4
[1]First Nations	13.5	3.6

Note: *Includes Force Majeure and Loss of Supply (i.e. interruptions due to Transmission events)*

Distribution System - Rural (2016 YE Performance)

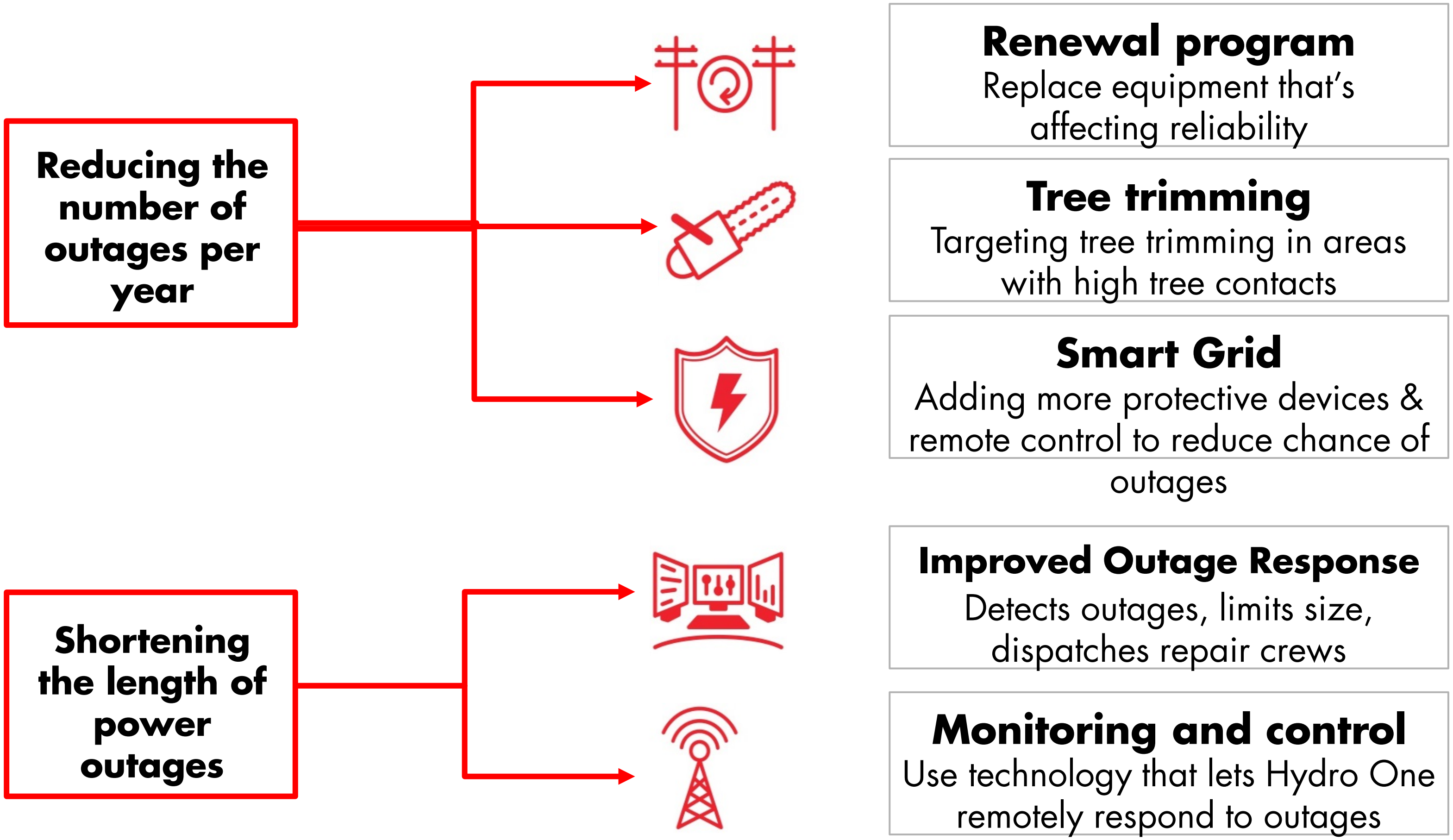
Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	14.6	3.7
[1]First Nations	13.5	3.6

Distribution System - Urban (2016 YE Performance)

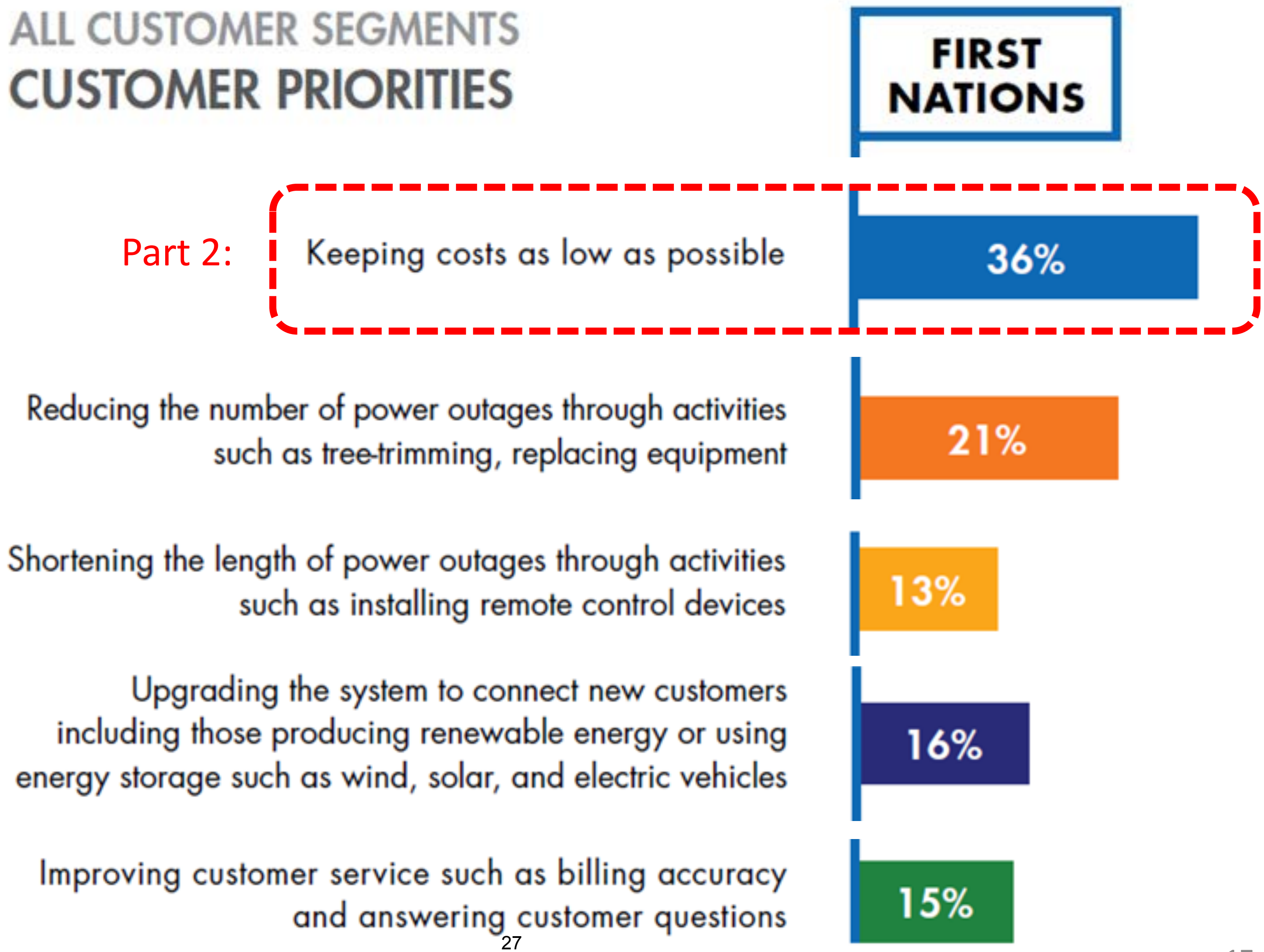
Distribution System Reliability Index	Interruption Hours/Customer (SAIDI)	# of Interruptions/Customer (SAIFI)
Hydro One	3.0	1.7
[1]First Nations	Mostly Rural	Mostly Rural

[1] First Nations results are for 2015 year. When available, 2016 numbers will be inserted. Only a small portion of First Nations are in an Urban area (<10% estimated)

How is Hydro One maintaining Reliability in the Distribution System?



Customer Engagement Results



Controlling Costs:

- **Pacing Expenditures**
- **Vegetation Management**
- **Move-to-Mobile**

Questions & Answers

Hydro One's Distribution Rates Application (2018-2022)

Oded Hubert

Vice President – Regulatory Affairs

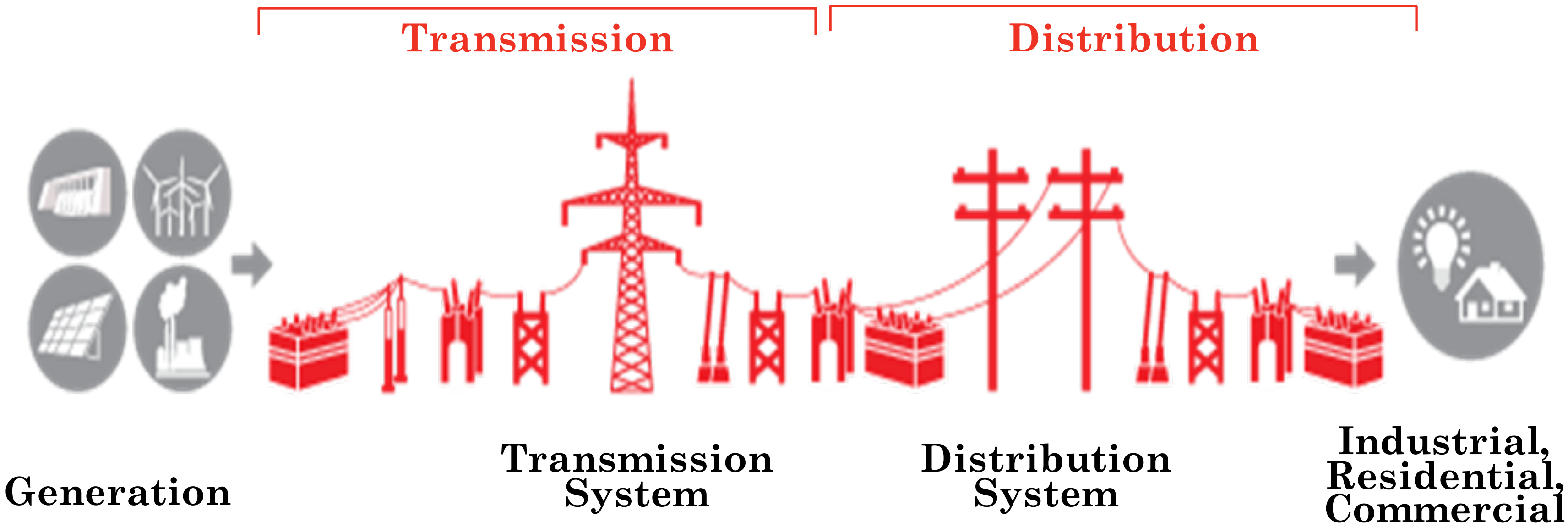
Hydro One and First Nations Engagement Session

February 9 and 10, 2017 30

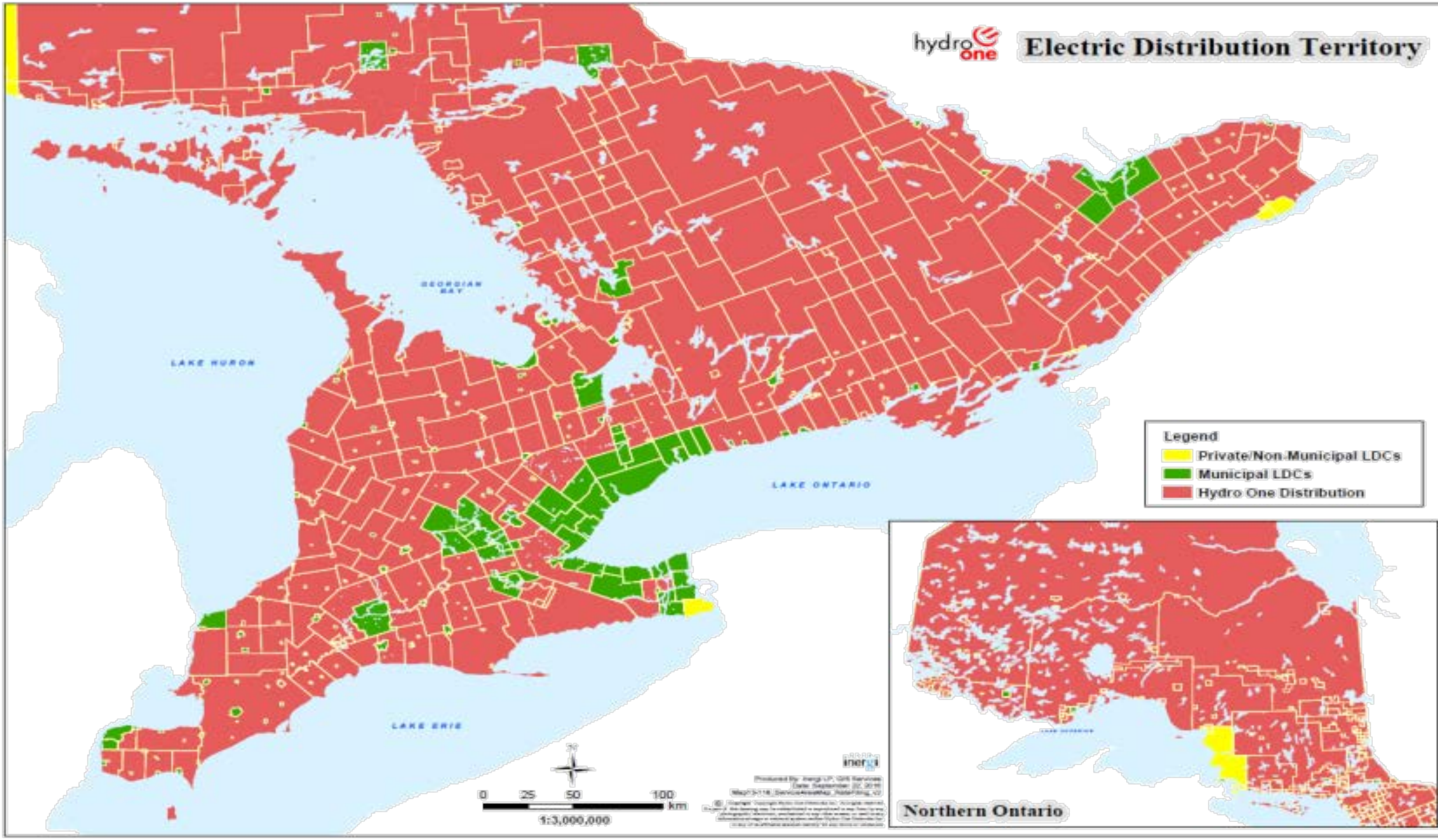
Hydro One Limited
(Hydro One)

- Hydro One is Ontario's largest electricity delivery company
- We are owned 70% by the province of Ontario and 30% by public shareholders
- We have three businesses:
  - Transmission;
  - Distribution; and
  - Telecommunications

Hydro One's Role in the Ontario Electricity System



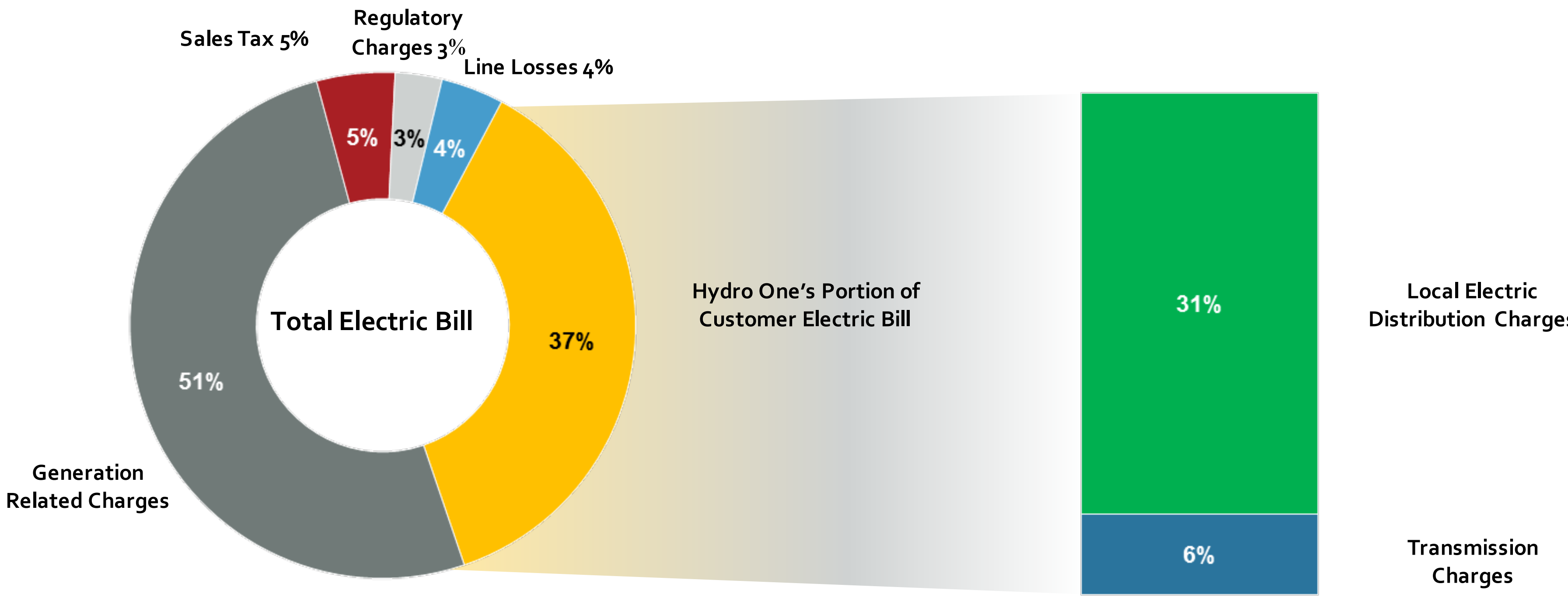
Distribution System Map



Distribution System Stats

Service Territory	Rural Service Area - 960,123 sq. km Urban Service Area - 677 sq. km
Customers	1.3 million residential and business customers as well as 55 local distribution companies
Distributed Generation	Approximately 13,400 small, mid-size and large embedded generators connected to Hydro One's distribution network, including approximately 12,600 generators with capacities of up to 10 kW and 1,600 generators pending connection
Stations	Approximately 1,000 distribution and regulating stations
Circuit Length	123,000 kilometres of primary low voltage distribution lines

Breakdown of Electricity Costs to Customers



How Distribution Rates are Set

- Electricity distribution rates are set by the Ontario Energy Board (OEB), an independent public agency.
- The OEB sets rates following a public hearing based on evidence.
- Hydro One will be applying to the OEB to set our distribution rates for the period 2018-2022 in March 2017.

Balancing Key Considerations

Hydro One's Application

Our proposal is focused on addressing customer needs and preferences including:

- **Keeping Costs Low**

  Keep costs as low as possible is customers' top priority

- **Maintain Reliable Service**

  Maintaining reliable electricity service is consistently second priority to cost

- **Large Customers**

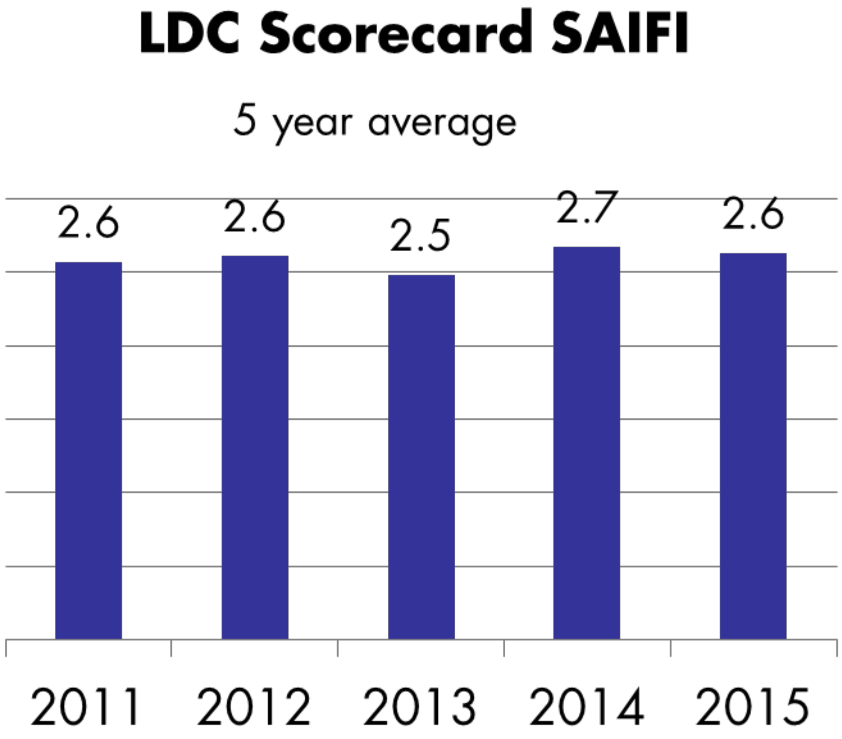
  Large customers are more concerned with reliability and capacity

- **Manage Rate Impacts**

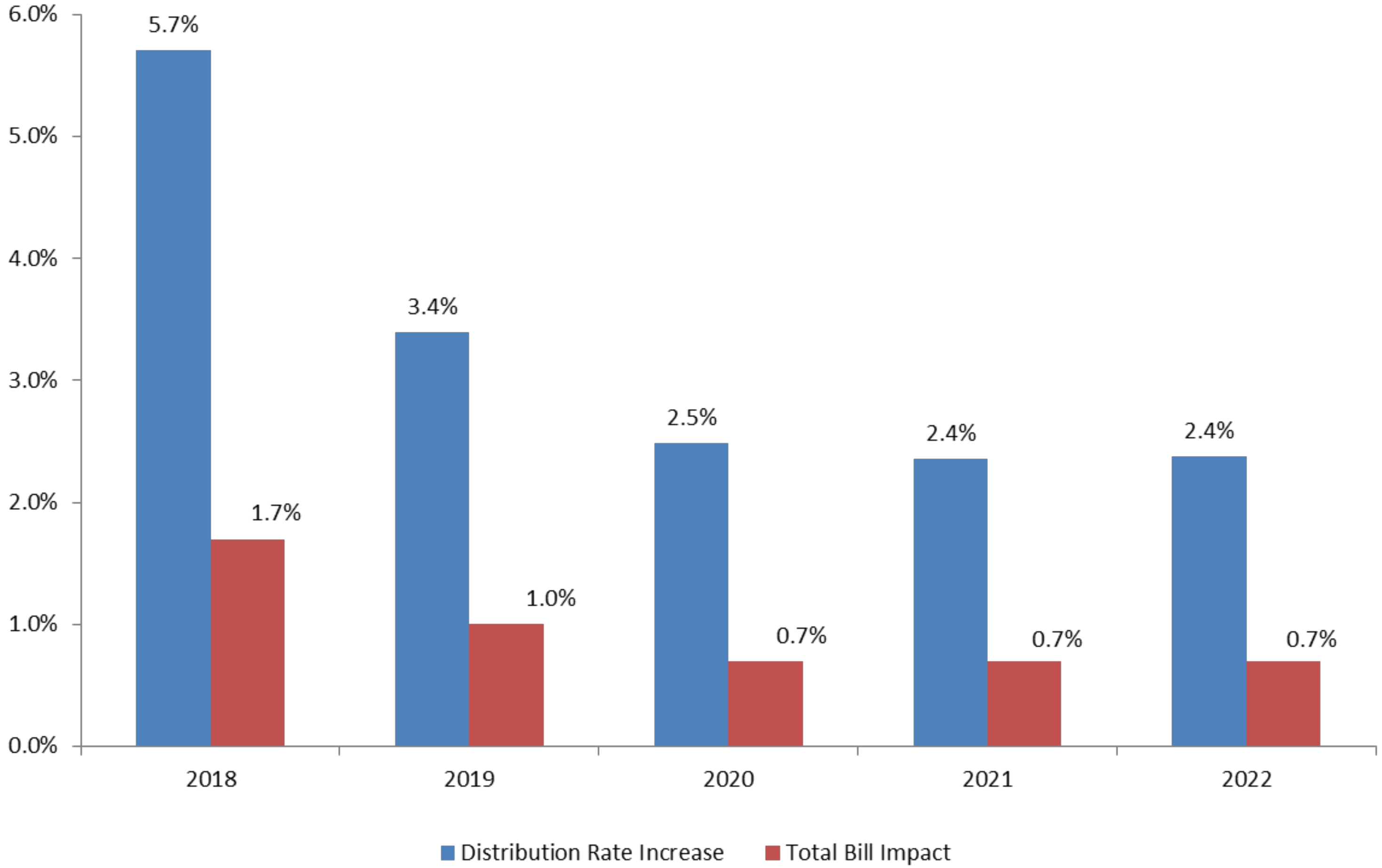
  Willingness to accept a rate increase to improve service level is limited

Service Enhancements Hydro One Will Deliver

Hydro One’s overall business plan was optimized such that asset condition and reliability will not deteriorate



Proposed Distribution Rate Increases And Total Bill Impact



Main Areas of Hydro One Rate Increases

Cost Drivers	2018	2019	2020	2021	2022
Operations, Maintenance and Administration	-0.1%	0.5%	0.5%	1.2%	0.5%
Capital Related (e.g., poles, wires and transformers)	2.0%	2.9%	2.6%	3.3%	2.5%
Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Load Impact	2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Other Revenue and Rate Riders	1.1%	0.0%	0.0%	-0.1%	0.0%
Total	5.7%	3.4%	2.5%	2.4%	2.4%

Additional Cost from Declining Electricity Use (Load Impact)

- The cost of distribution services is spread out among all Hydro One customers based on total electricity consumption.
- Total electricity consumption has been decreasing since rates were last set, so the cost of serving each individual customer will increase by 2% in 2018.
- This is a one-time adjustment and will not lead to increases in 2019-2022.

On-Reserve First Nations Electricity Customers

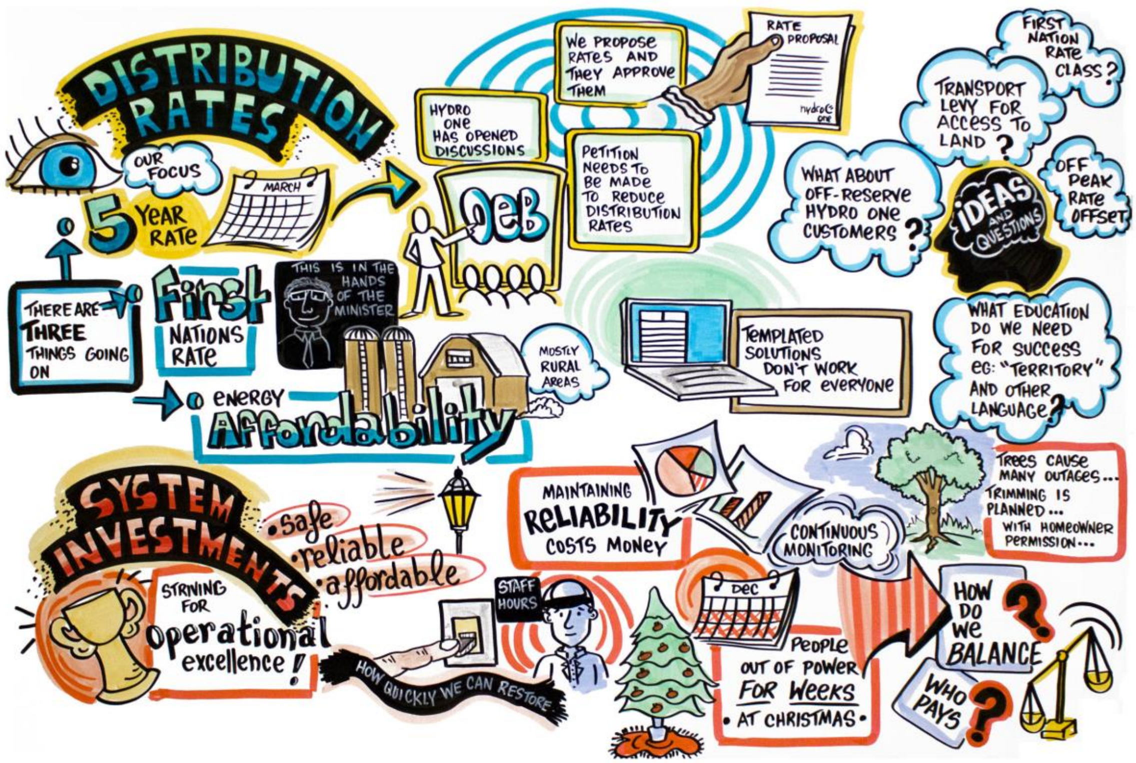
- Minister of Energy asked the OEB to examine and provide advice for an appropriate electricity rate or rate assistance program
- Hydro One has been supportive of this initiative and has provided input to the OEB
- January 1, 2017 OEB submitted its report to the Minister of Energy and now waiting for next steps to be announced.

Questions & Answers

THANK YOU FOR ATTENDING!

HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10

HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10



HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10


SHARING WHAT YOUR COMMUNITY MEMBERS ARE SHARING WITH YOU
HYDRO ONE
FIRST NATIONS
RESPECT
CROSS CULTURAL EDUCATION
THE Leaders AND Decision Makers ARE IN THE ROOM
ENGAGEMENT SESSION NOT CONSULTATION
A BIG FIRST STEP
FIRST OF MANY!
TIME TO MOVE FORWARD
EACH COMMUNITY IS DIFFERENT
TURNING THE CORNER ON THE PAST • MUTUALLY AGREEABLE •
Relationships
Listen
RESPECT PROTOCOLS
TAKE Time
WHEN I SEE A TRUCK... I EXPECT IT'S DISCONNECTION
DISCONNECTION
FEES COLLECTED DON'T COME TO US!
EDUCATION
ISSUES
OUR COMMUNITIES CAN'T AFFORD TO HEAT THEIR HOMES
POWER IS A NECESSITY!
OUR ELDERS NEED HELP
DELIVERY CHARGES
OUTWEIGHS CONSUMPTION!
BILL
TAX EXEMPTION
HYDRO ELECTRIC DAMS
LINES UNDERWATER
POLES
ENVIRONMENTAL IMPACT
SPRAYING
THIS IS PRODUCED FROM OUR LAND...
NO ONE WANTS TO TAKE BLAME!
WITH ACCESS TO OUR LAND
PEOPLE SHOULDN'T HAVE TO RELY ON OTHERS TO PAY... LOSS OF PRIDE IS AN ISSUE
WE CANT JUSTIFY HIGH PROFITS WHEN PEOPLE ARE CHOOSING
FOOD OR POWER
But...
URBAN AREAS WITH HIGHER INCOMES PAY FAR LESS
Treaty
STILL WAITING FOR PROMISES TO BE FULFILLED!
1850...
HYDRO IS A RESOURCE FROM MOTHER EARTH
SEWAGE
POLLUTION
1951
A PROMISE WAS MADE TO PROVIDE POWER AT NO COST
UNDERSTANDING
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10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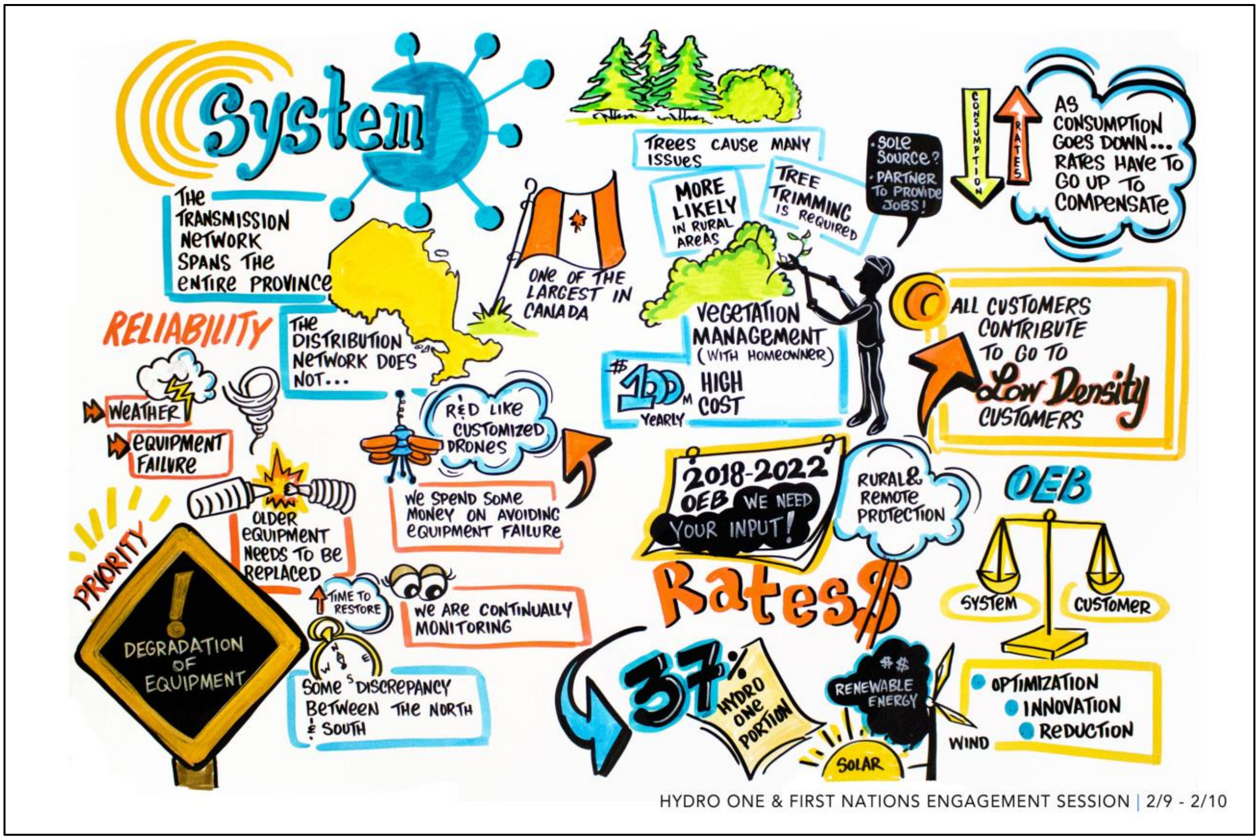
GOING THROUGH MANY Changes
WE ARE IN THE WIRING BUSINESS
BILL
WE PLAY A PART IN NEGOTIATING DELIVERY CHARGES
ADVOCACY
IT'S TIME FOR CHANGE!
TOGETHER WE CAN INFLUENCE
FIX THE SYSTEM
IT'S A CRISIS
DISTRIBUTION RATE FILING
NO FEE
WORKING WITH INDIVIDUALS TO HELP THEM
FIRST NATIONS RATE
50% GENERATION COST
CALL TO ACTION
LOWER COST
ACTION
TREATY RIGHTS
RECONNECTION PROGRAM
PAYMENT PLANS
I WANT TO PAY... I CAN'T!
EDUCATION
HOW THE SYSTEM WORKS
BECOME MORE EFFICIENT
WATCH OUR COSTS
PRESENTING TO POLICY MAKERS ON AFFORDABILITY
WE HAVE MADE OVER 200 COMMUNITY VISITS TO DATE
1/3 (AVERAGE) DISTRIBUTION BUT BASED ON DENSITY
COST RECOVERY SYSTEM
COST IS LOWER WHERE MORE SHARE THE BURDEN
RURAL
New PROGRAMS
ADDRESS ISSUES
RIGHTS HOLDERS
YOU ARE
PARTNERS
EMPLOYEES
MET WITH 600 CUSTOMERS TO DATE
ASKING FOR CHANGE
HIGH CONSUMPTION + HIGH DELIVERY + POVERTY = CRISIS
ELECTRIC HEAT MOSTLY
INSULATION ISSUES
ANALYSIS
MEETINGS
RATE FILING
EDUCATION
2 WAY
GLOBAL ADJUSTMENT
POS EXEMPTION (OFF AND ON RESERVE)
DISTRIBUTION CHARGE
BILL
CONSUMPTION HIGH DELIVERY HIGH
TRANSMISSION LINES ON OUR LAND
SHOULD BE BRINGING IN REVENUE BUT ISN'T...
WE NEED TO WORK TOGETHER TO RESOLVE WITH DECISION MAKERS
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10


System
The transmission network spans the entire province
The distribution network does not...
One of the largest in Canada
Trees cause many issues
More likely in rural areas
Tree trimming is required
• Sole source?
• Partner to provide jobs!
Consumption
Rates
As consumption goes down... rates have to go up to compensate
Vegetation management (with homeowner)
$100M yearly
High cost
All customers contribute to go to Low Density customers
Reliability
Weather
Equipment failure
R&D like customized drones
We spend some money on avoiding equipment failure
Older equipment needs to be replaced
Priority
Degradation of equipment
Time to restore
We are continually monitoring
Some discrepancy between the North & South
2018-2022 OEB We need your input!
Rural & remote protection
OEB
System
Customer
Rates$
37% Hydro One portion
$$ Renewable energy
Solar
Wind
• Optimization
• Innovation
• Reduction
HYDRO ONE & FIRST NATIONS ENGAGEMENT SESSION | 2/9 - 2/10

Aboriginal Procurement: Doing Business with Hydro One

2017 Métis Nation of Ontario Engagement Session

Aboriginal Procurement Procedure

- Procedure supports the First Nations & Métis Relations policy through procurement opportunities for qualified Aboriginal businesses
- Goals:
  - Promote business and workforce development for Aboriginal Businesses
  - Diversify supplier base
  - Increase access to Procurement opportunities for Aboriginal Businesses

Aboriginal Procurement Procedure

hydro one

- There are 3 approaches to provide opportunities to Aboriginal businesses:

  1. Aboriginal Participation is preferred
  2. Competition is limited to qualified Aboriginal businesses
  3. Direct Award to qualified Aboriginal businesses

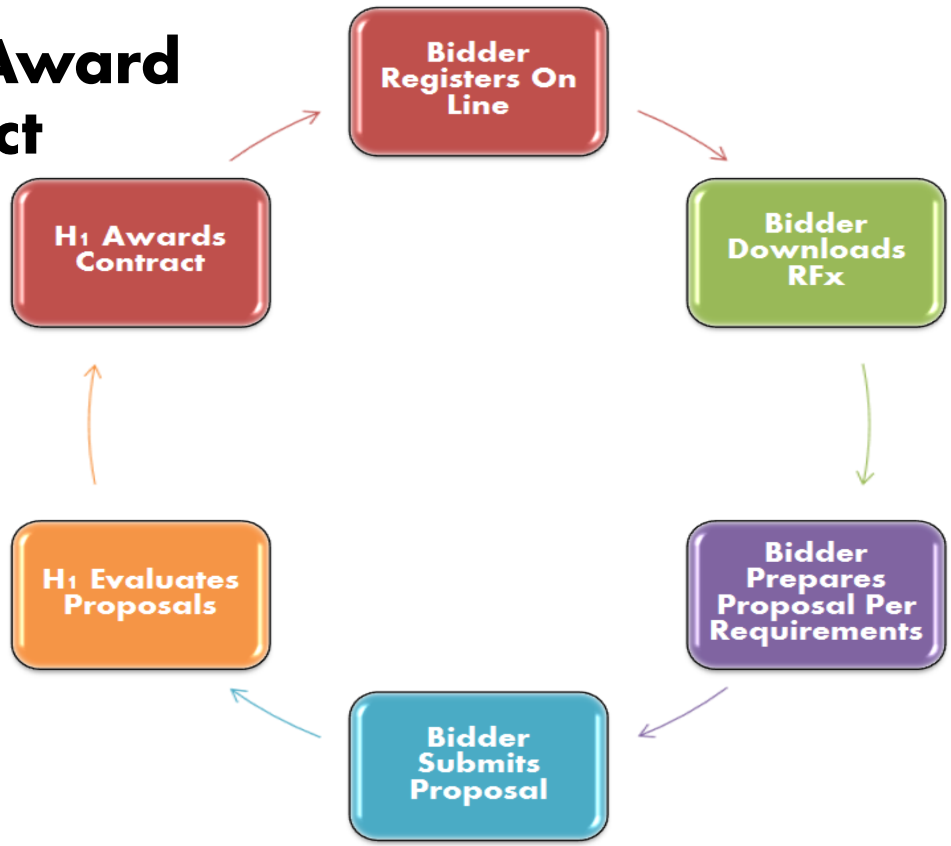
Procurement at Hydro One

Types of materials and services purchased

- Heavy duty equipment (floats, trucks, backhoes, cranes, etc.)
- Road construction services
- Aggregate and concrete
- Fencing
- Forestry/vegetation management services
- Pole digging and rock drilling services

Procurement at Hydro One

6 Steps to Award Contract



BID System - Key Concepts

- Bidders can retrieve all RFx types from the BID System
- Only RFQs are submitted in the BID System
- All other RFx (RFP, RFPQ, RFI) will be submitted as directed in the individual RFx

BID System - Online Registration

- To register for the BID System, go to

  http://www.HydroOne.com/doingbusiness
- Select **Bidder Registration**
- Complete all required fields (*) such as company name, email address, etc.
- During registration, the option to self-identify as an Aboriginal Business is available

BID System - Reference and Contact Information

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- A complete guide on using the Bid System entitled **How to Instructions** can be found on the Doing Business with Hydro One webpage:

  http://www.HydroOne.com/doingbusiness

- For inquiries related to registration or access to the Bid System, please contact:

  BidderRegistrationHelp@HydroOne.com

- For all other general inquiries, please contact:

  NewVendorInquiries@HydroOne.com

Bidding Documents – Process & Qualifications

- RFP Process Requirements
  - RFP schedule and submission process
  - Evaluation considerations
  - Key commercial terms
- Qualifications
  - Labour Requirements as applicable
  - Insurance Requirements/WSIB
  - Health and Safety

Aboriginal Participation

hydro one

- RFQs include Aboriginal business declaration
- All RFPs include Aboriginal Participation
  - – Evaluation Criteria are:
    - Ownership of bidder or partners
    - Subcontractors
    - Aboriginal community/personnel involvement in the delivery of the materials/services
      - o Focus on local Aboriginal persons and businesses
    - Active diversity programs and policies

Aboriginal Participation - Self-Identifying

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- Hydro One considers an Aboriginal business:
  - One which is at least 51% owned and controlled by an Aboriginal business(es) or person(s) and
  - If the firm has six or more full-time staff, at least 33% of the employees are of Aboriginal descent
- Joint Ventures or Partnerships:
  - Must be at least 51% owned and controlled by an Aboriginal business(es) or person(s)
  - 33% of the value of the work must be performed by an Aboriginal business (e.g. partner, subcontractor)

Aboriginal Participation - Self-Identifying

- Addition to Hydro One's Aboriginal Business Directory must be requested. Email:

  NewVendorInquiries@HydroOne.com

- A **Consent to Disclose Contact Information** form must be completed and returned to Hydro One for verification.
- Suppliers can search for Aboriginal businesses for sub-contracting or to partner

Opportunities – Upcoming RFPs

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- Construction Materials – Aggregate & Concrete
- Office Trailers – RFP scheduled for 2018
- Printing Services – June/July
- Uniform and Laundry Services
- Pest Control
- Health Assessments
- Meter Replacements
- Directional Road Boring
- Rebar – 2Q 2017

Resources

- www.HydroOne.com/DoingBusiness
- New Vendor Inquiries: NewVendorInquiries@HydroOne.com
- BID System Help Desk: BidderRegistrationHelp@HydroOne.com
- www.HydroOne.com/FirstNationsMetis
- eInvoicing: http://supplier.taulia.com/customers/hydroone/

Questions

CUSTOMER SERVICE

Imran Merali

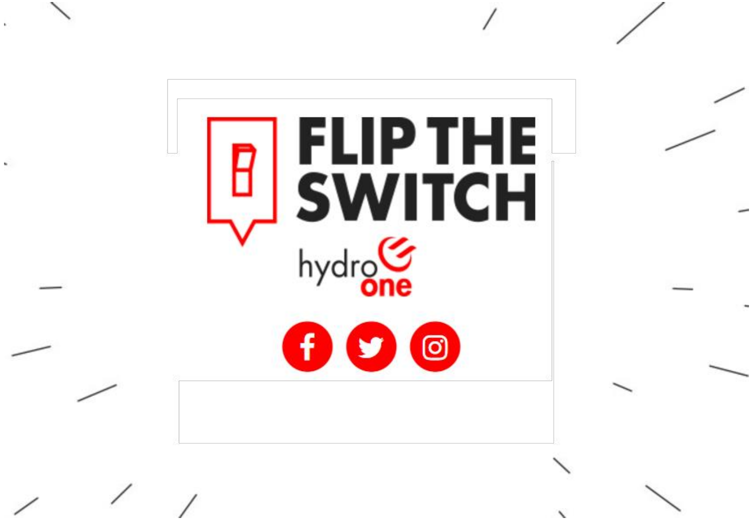
Director Customer Program Delivery

Métis Engagement Session

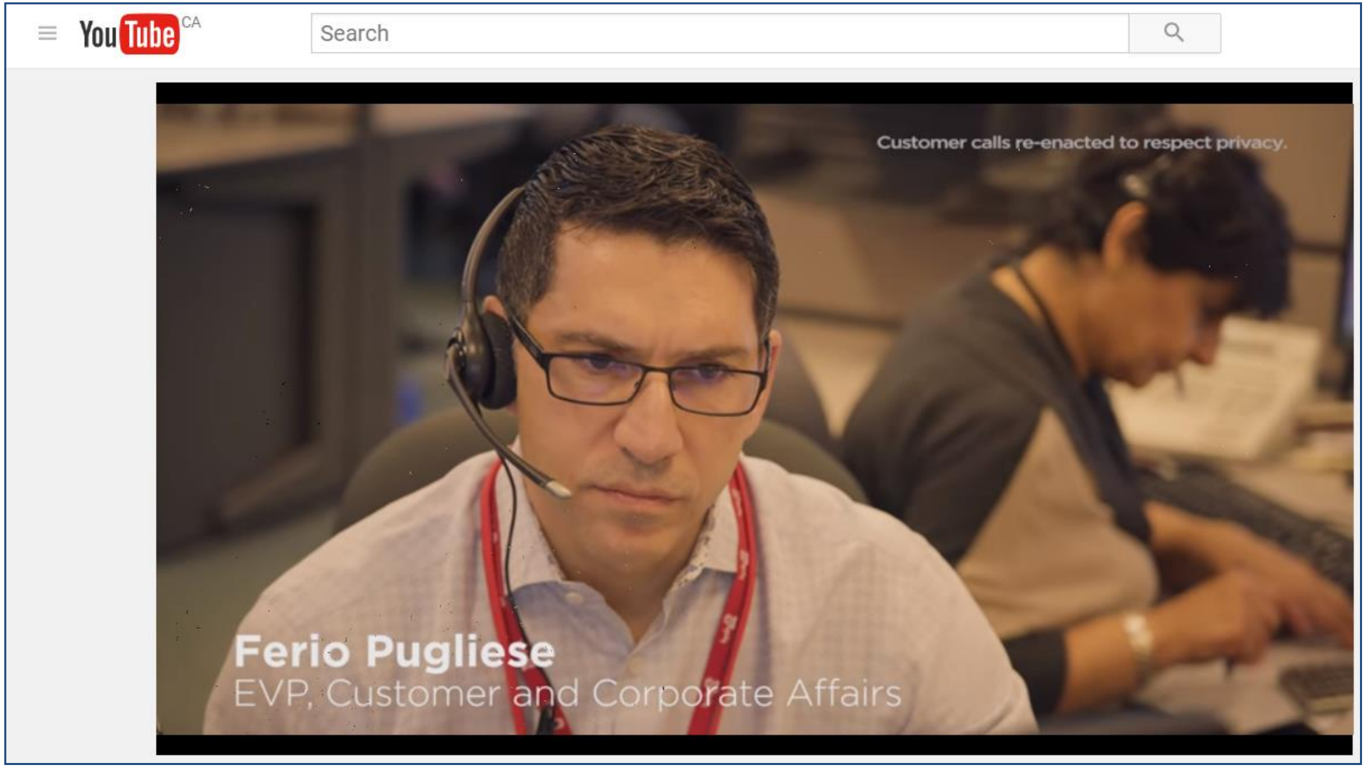
May 13, 2017

Flip the Switch

- **Flip the Switch** is our new commitment to customers to better listen and respond to their questions and concerns.



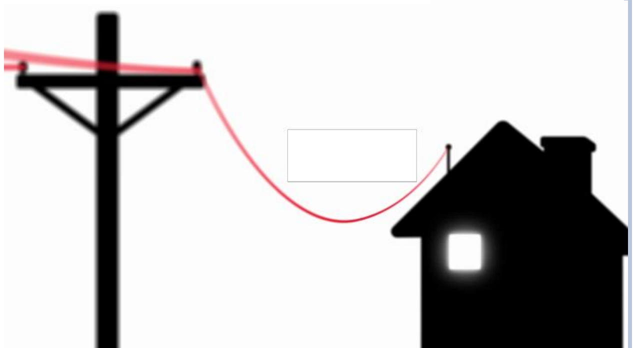
Flip the Switch Video



http://fliptheswitch.hydroone.com/hydrooneday

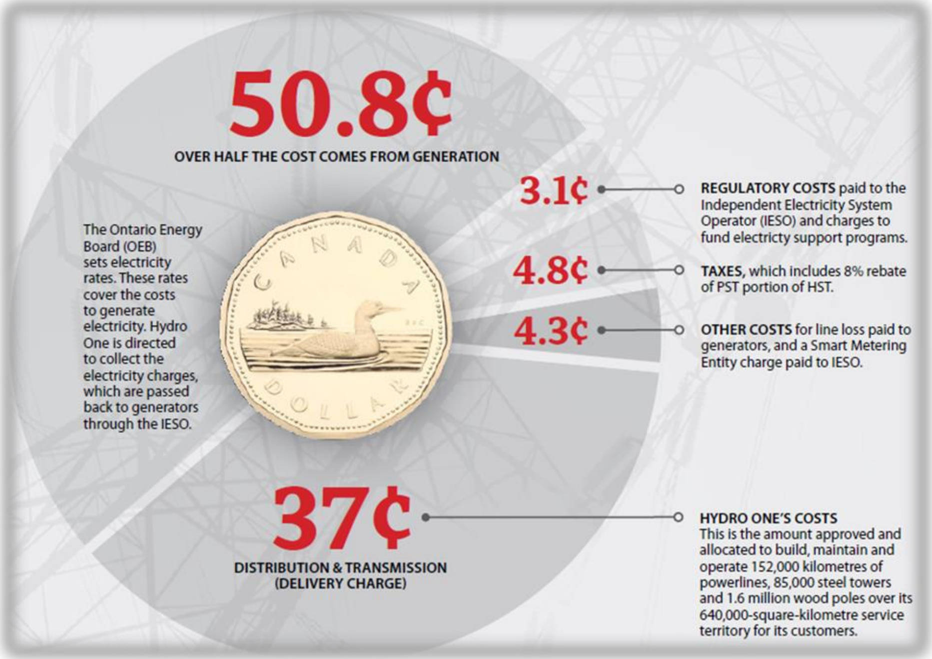
Customer Service Vision

- We are easy to do business with
- We are there when customers need us
- We are always connected



We Are Easy To Do Business With

- Education
- Advocacy
- Responsiveness



Fair Hydro Plan

- On March 2, the government announced changes that will provide significant electricity bill relief. As a result, Hydro One customers will start to see lower monthly bills as early as this summer. We advocated for these changes because we heard your concerns. That's the new Hydro One.

- The Province has introduced plans to bring relief and fairness to electricity bills by:
  - Reducing the Global Adjustment charge
  - Lowering the Delivery charge for residential customers with a low or medium density service type
  - Eliminating the Delivery charge for customers living on a reserve
  - Introducing an Affordability Fund to help those customers in need
  - Enhancing the Ontario Electricity Support Program

Fair Hydro Plan CON'T

- Customers will start to feel the relief as early as this summer.
- The average Hydro One customer will start to see their monthly bills drop by an average of 33 per cent.

Average Residential Medium Density (1,000 kWh per month)

2017 Charges	Charges before Fair Hydro Plan	New charges with Fair Hydro Plan	Savings
Electricity	$111.39	$80.54	$30.85
Delivery	$78.59	$57.47	$21.12
Regulatory Charges	$7.57	$4.55	$3.02
Taxes	$25.68	$7.13	$18.55
Total Monthly Savings			$73.54 (33%)

Average Residential Low Density with electric heat (2,400 kWh per month)

2017 Charges	Charges before Fair Hydro Plan	New charges with Fair Hydro Plan	Savings
Electricity	$267.34	$193.30	$74.04
Delivery	$167.92	$88.56	$79.36
Regulatory Charges	$18.28	$10.86	$7.42
Taxes	$58.96	$14.64	$44.32
Total Monthly Savings			$205.14 (40%)

Customer Relief Program

- Effective April 25th, Hydro One is providing additional relief to assist customers that accumulated significant balances on their accounts over the winter .
- These measures aim to help customers better manage their electricity usage to get back on track and avoid future disruption to their electricity service.
- The policy changes include:
  - Eliminating Residential Security Deposits
  - Reducing Deposit Requirements for Businesses
  - New Customer Relief Measures
  - Additional Low Income Funding
  - Extending our Winter Moratorium until June 1, 2017

Customer Commitments

- Hydro One also introduced Service Guarantees, a first of its kind for any electric utility in Ontario.
- These provide tangible evidence that we stand behind the service we provide our customers.

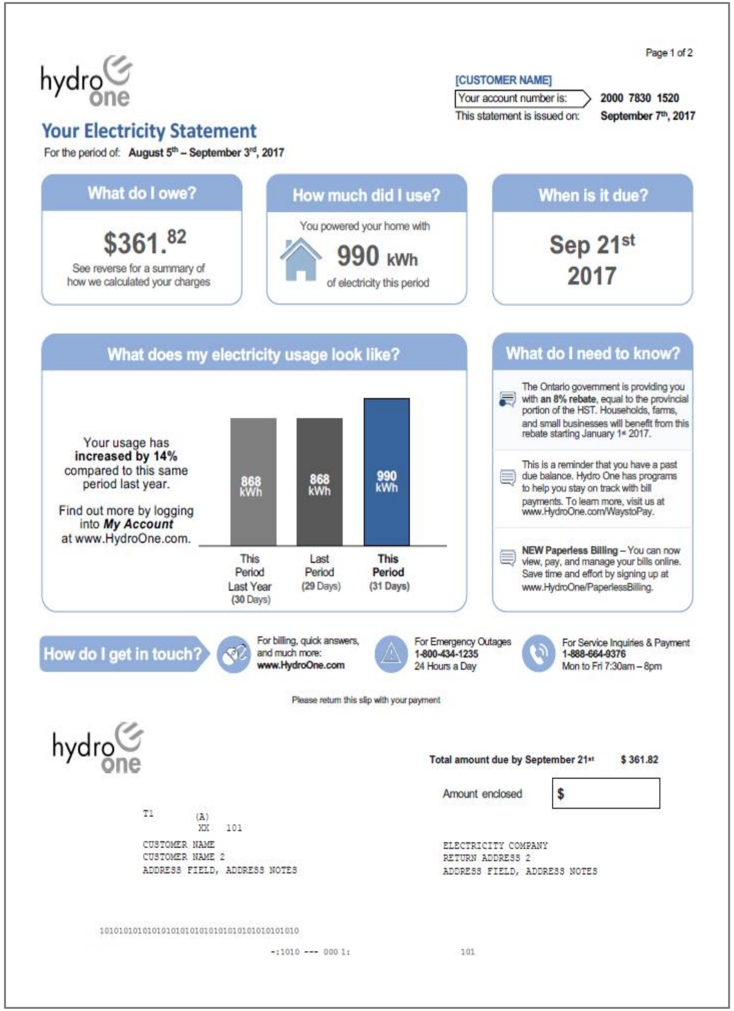
If We Miss Our Appointment With You, We Will Credit Your Account $75

If We Don't Connect Your New Service Within 5 Business Days of All Connection Requirements Being Met, We Will Credit Your Account $75.

If We Don't Return Your Phone Call Within 1 Business Day, We Will Credit Your Account $75

Billing

- Billing Accuracy continues to surpass Ontario Energy Board requirements and is the **highest in company history** at 99%.
- Hydro One is also introducing a newly designed bill in the fourth quarter of 2017 (pictured).



Page 1 of 2

hydro one

[CUSTOMER NAME]
Your account number is: 2000 7830 1520
This statement is issued on: September 7th, 2017

Your Electricity Statement
For the period of: August 5th – September 3rd, 2017

What do I owe?
$361.82
See reverse for a summary of how we calculated your charges

How much did I use?
You powered your home with 990 kWh of electricity this period

When is it due?
Sep 21st 2017

What does my electricity usage look like?
Your usage has **increased by 14%** compared to this same period last year.
Find out more by logging into ***My Account*** at www.HydroOne.com.

What do I need to know?
The Ontario government is providing you with **an 8% rebate**, equal to the provincial portion of the HST. Households, farms, and small businesses will benefit from this rebate starting January 1st 2017.
This is a reminder that you have a past due balance. Hydro One has programs to help you stay on track with bill payments. To learn more, visit us at www.HydroOne.com/WaystoPay.
NEW Paperless Billing – You can now view, pay, and manage your bills online. Save time and effort by signing up at www.HydroOne/PaperlessBilling.

How do I get in touch?
For billing, quick answers, and much more: **www.HydroOne.com**
For Emergency Outages **1-800-434-1235** 24 Hours a Day
For Service Inquiries & Payment **1-888-664-9376** Mon to Fri 7:30am – 8pm

Please return this slip with your payment

hydro one

Total amount due by September 21st **$ 361.82**
Amount enclosed $

T1 (A) XX 101
CUSTOMER NAME
CUSTOMER NAME 2
ADDRESS FIELD, ADDRESS NOTES

ELECTRICITY COMPANY
RETURN ADDRESS 2
ADDRESS FIELD, ADDRESS NOTES

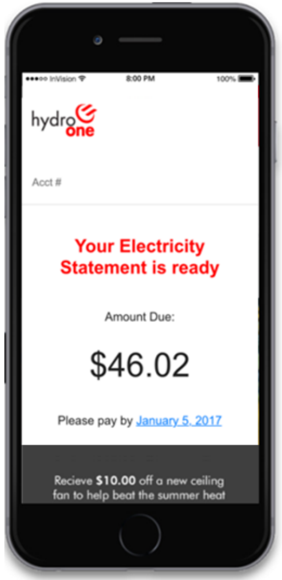
1010101010101010101010101010101010101010
-:1010 --- 000 1: 101

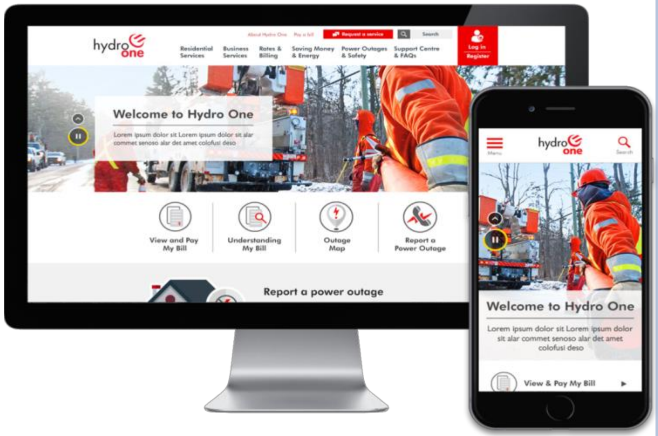
We Are Always Connected

eBill Notifications & High Usage Alerts

New Website

Redesigned Bill





Employment and Training

Overview

- Objective
- Our Commitment
- Apprenticeships
- Co-ops and Internships
- New Grad Program
- Summer Student Outreach Program
- Scholarships
- Reminders and Contact Information

Objective

Hydro One will strive to become a workplace of choice for First Nations and Métis people in Ontario, through active recruitment, retention, and promotion

Our Commitment

hydro one

Commit resources for recruiting, retaining and developing Aboriginal talent to achieve equitable representation of Aboriginal persons in the workplace including supporting cross cultural awareness/sensitivity training.

Apprenticeships

- Hydro One typically hires four trades:
  - Powerline Technician
  - Utility Arborist/Forester
  - Construction & Maintenance Electrician
  - Coach & Truck Technician
- Detailed information can be found at: www.HydroOne.com/Careers and www.TradeUp.ca
- Hiring for each apprenticeship normally occurs in the fall

Powerline Technician (Lines)

Working Conditions

hydro one

- Outdoors
- All weather conditions
- Physically Demanding
- Confined spaces
- Different locations throughout Ontario
- 5 days @ 8 hours or 4 days @ 10 hours

Apprenticeship Process:

- Hydro One has an apprenticeship program which is jointly offered through Hydro One and the PWU.
- Applications are accepted through the www.PWU.ca website and Aboriginal.Recruitment@HydroOne.com
- Include resume and cover letter
- Interview

Co-ops and Internships

- College or University Students
  - Must be enrolled in an eligible co-op or internship program
- Co-op: 4 to 8 month work terms
- Internship: 8 to 12 month work terms
- Positions posted every 4 months (winter, summer, fall)
- Positions offered across Ontario
- Students selected via interview
- Lunch and Learns/ Tours

New Grad Training Program

hydro one

- Two year training program for university graduates from engineering and business programs
- Rotations to different departments and business units in the company across Ontario
- Continuous learning and opportunities to upgrade your skills over two years
- Positions are posted each September
- Lunch and Learns/Tours/Training

Summer Student Outreach Program

- Requirements:
  - Must be of First Nation, Métis or Inuit ancestry
  - Attending a post-secondary institution and scheduled to return
- General Clerical or Labourer positions offered across Ontario
- Positions posted in February
- 4-month summer term (May-August), two term maximum

Scholarships

- Leonard S. (Tony) Mandamin scholarship annual award
  - Awarded to students enrolled in electricity industry related programs at a recognized Ontario college or university
- Includes both a financial award and developmental work term

  - **Deadline: October 1st**

- Guidelines and application available at: www.HydroOne.com/OurCommitment/AwardsScholarships

Want to Know More?

- Careers Website:

  http://www.HydroOne.com/Careers

- Questions related to employment:

  Aboriginal.Recruitment@HydroOne.com

- Hydro One First Nations and Métis Relations:

  http://www.HydroOne.com/FirstNationsMetis

Thank You

Hydro One Distribution Rates Application (2018-2022)

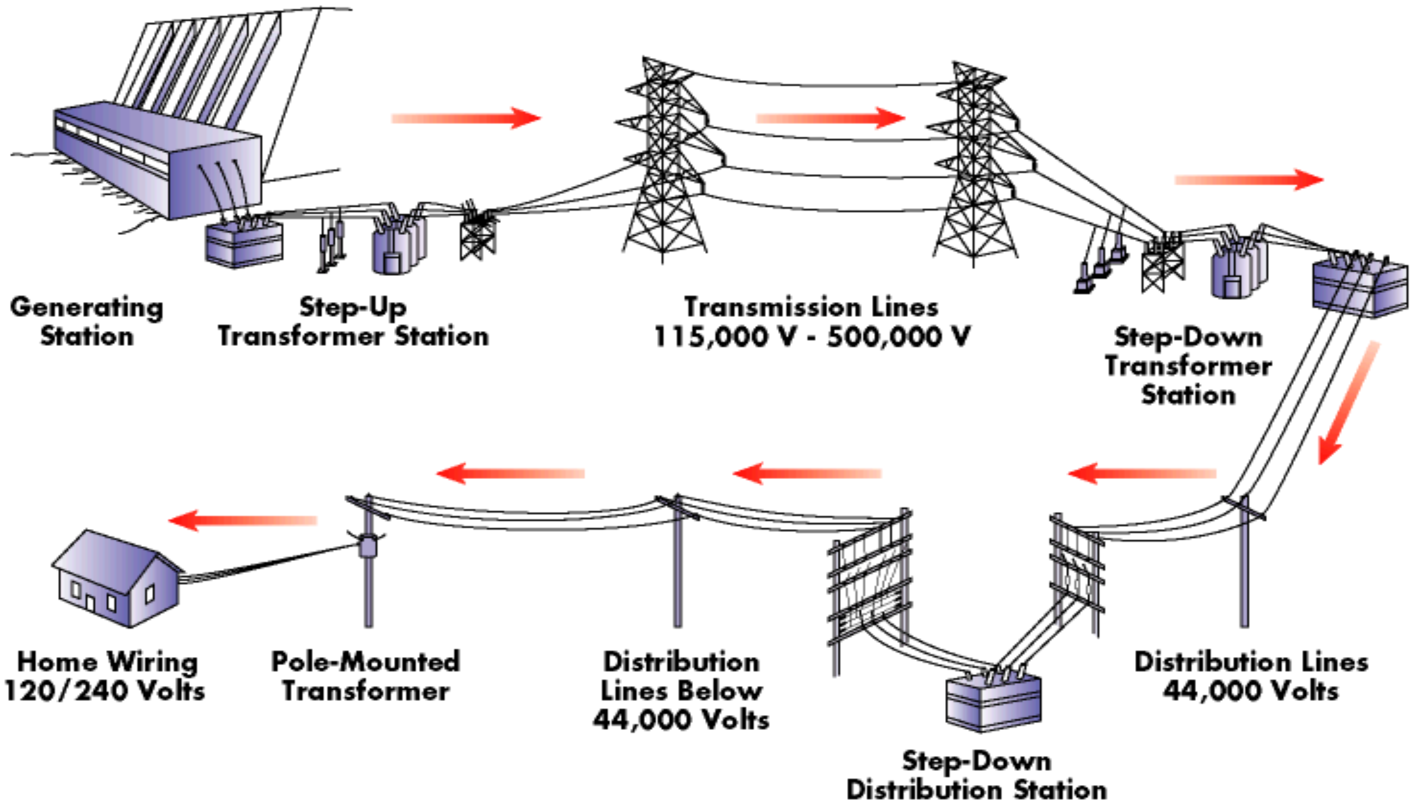
Oded Hubert

Regulatory Affairs

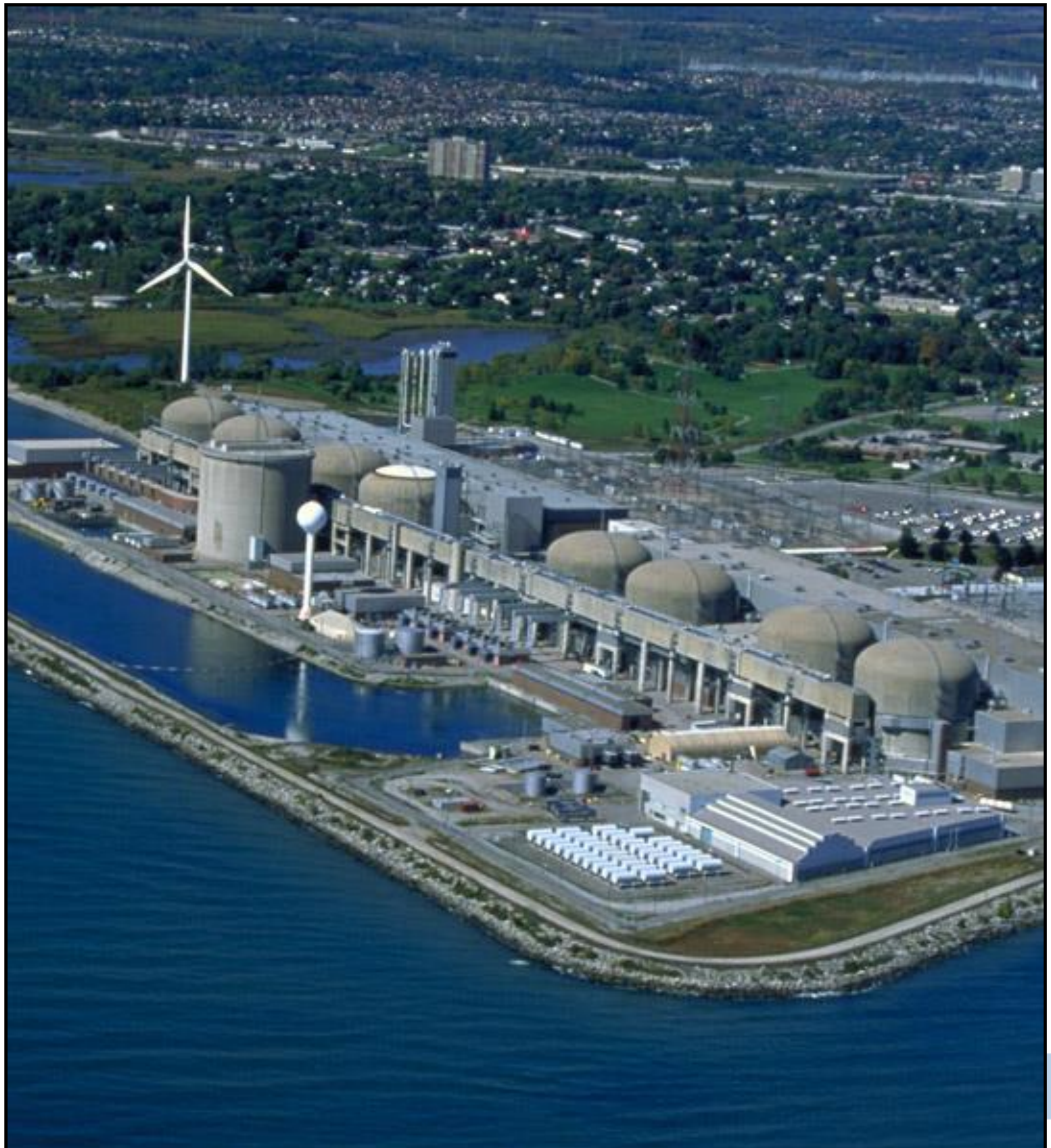
May 13th, 2017

Overview of Ontario's Electricity System

- Typical components and electricity flow from generator to customer.



Generators in Ontario’s Electricity System



Bruce Power

Algonquin Power

TransAlta

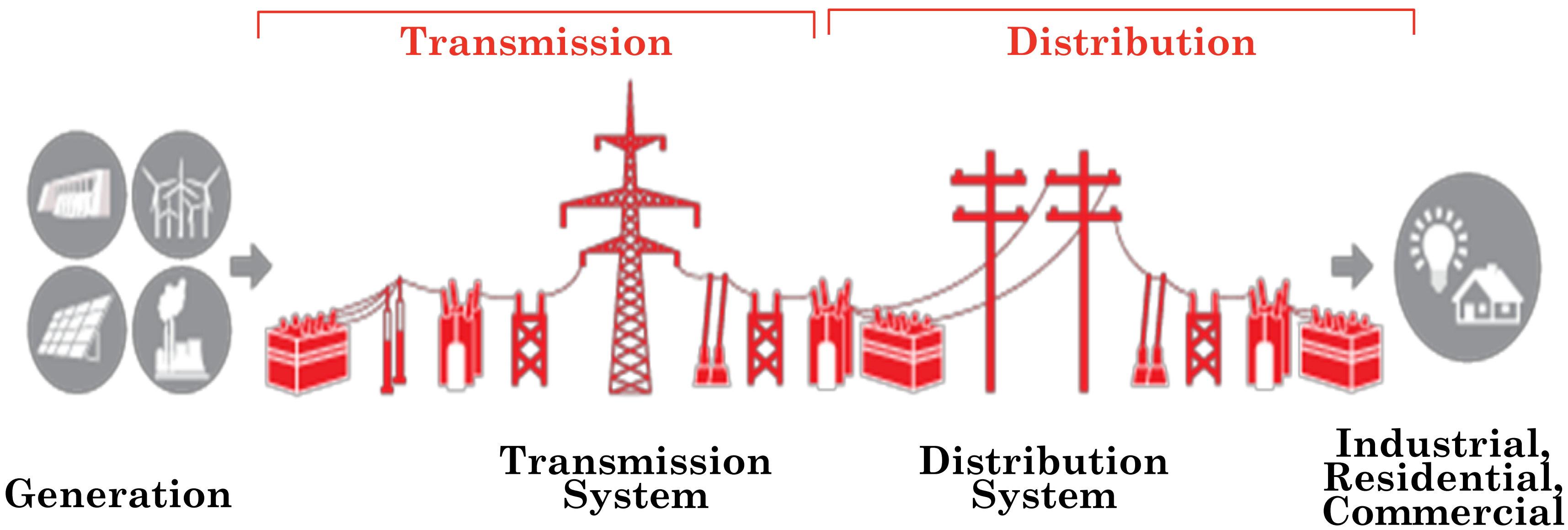
Brookfield

Sithe Global

Ontario Power Generation

AIMPOWERGEN
PART OF THE REG GROUP

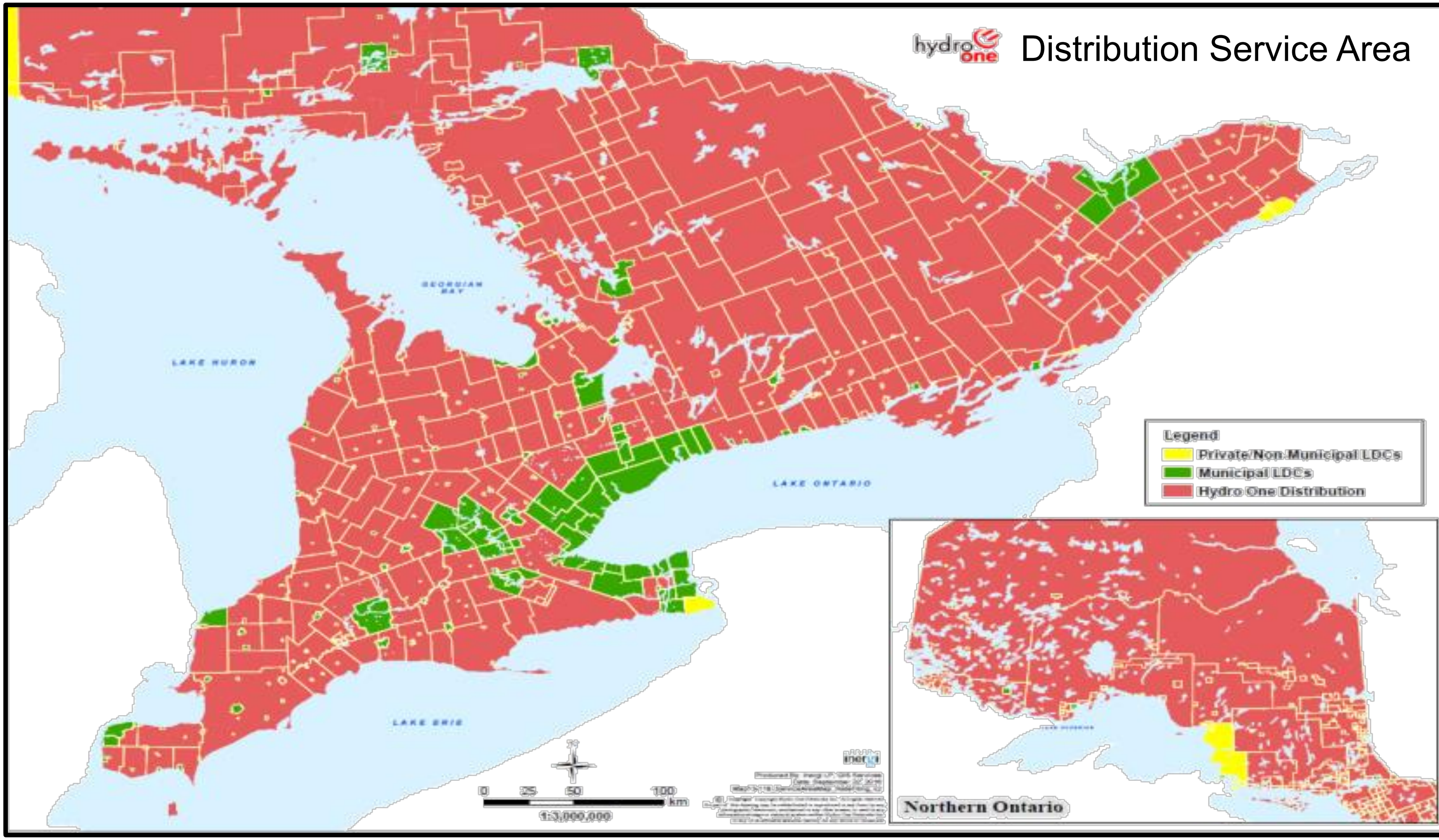
Hydro One's Role in the Ontario Electricity System



Hydro One's Transmission System Map

Hydro One's 230kV Transmission Lines

Hydro One's Distribution System Map

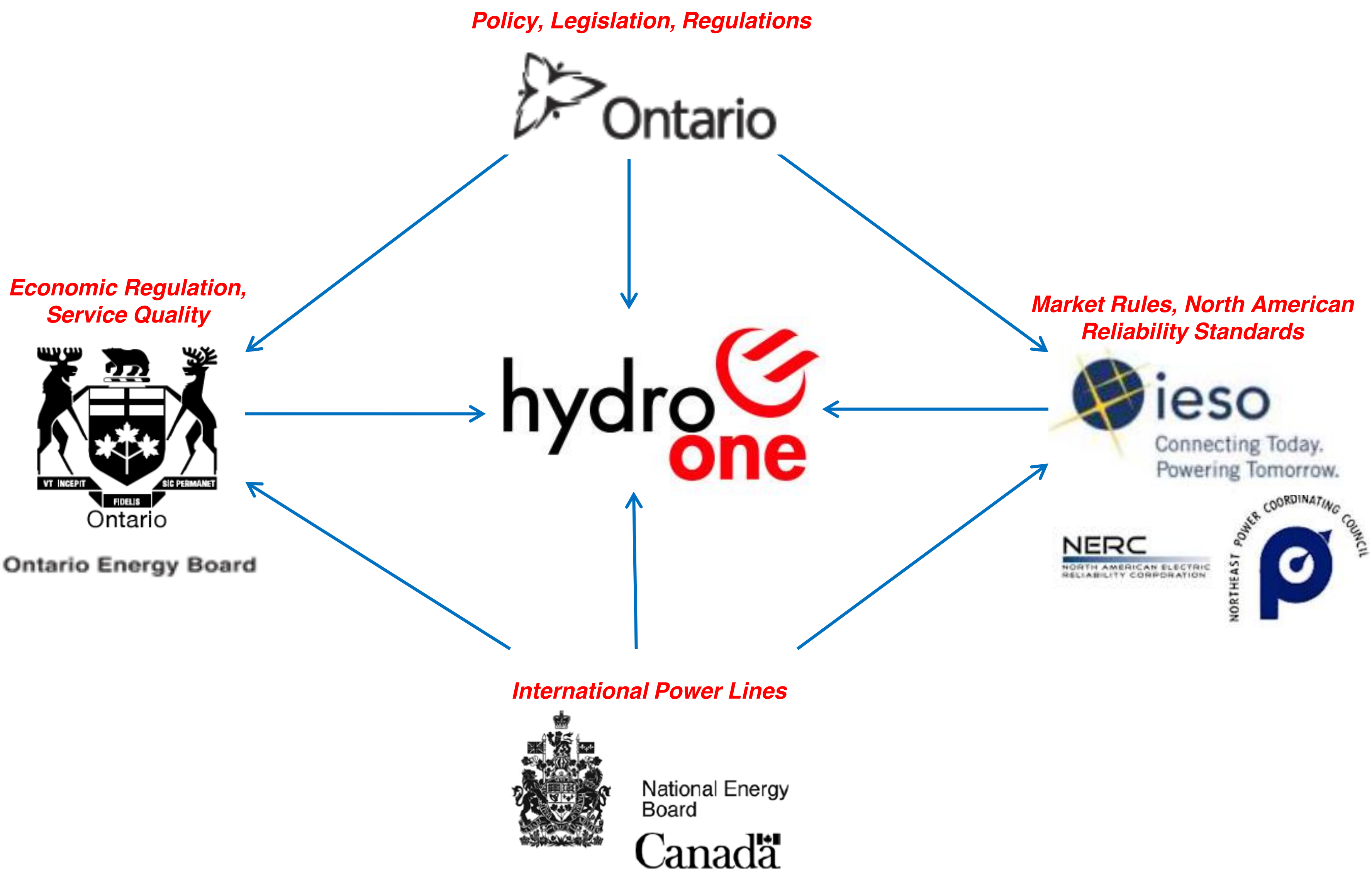


Hydro One's Rural Distribution Line

Overview of Hydro One' s Distribution System

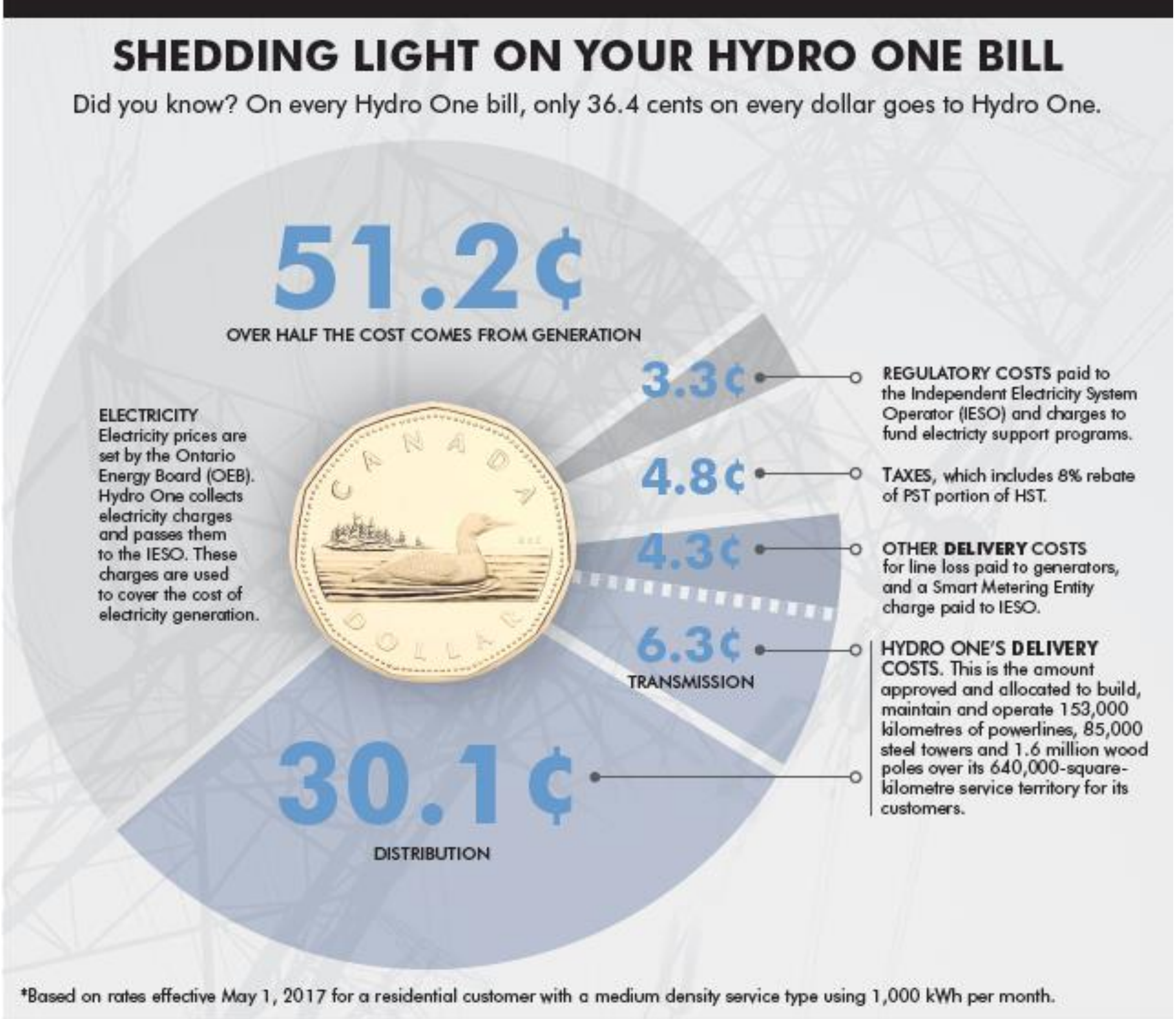
Service Area	Rural Service Area – 960,123 sq. km Urban Service Area – 677 sq. km
Customers	1.3 million residential and business customers as well as 55 local distribution companies.
Distributed Generation	Approximately 13,400 generators connected to Hydro One's distribution system.
Stations	Approximately 1,000 distribution and regulating stations.
Circuit Length	Approximately 123,000 km of primary low voltage distribution lines.

Ontario's Regulatory Framework



2018-2022 Distribution Rates Application

- Filed with the OEB March 31, 2017
- 5-year Incentive Rate-setting Application
- Includes a proposal for sharing earnings with customers
- Public hearing process about to start


SHEDDING LIGHT ON YOUR HYDRO ONE BILL
Did you know? On every Hydro One bill, only 36.4 cents on every dollar goes to Hydro One.
51.2¢
OVER HALF THE COST COMES FROM GENERATION
ELECTRICITY
Electricity prices are set by the Ontario Energy Board (OEB). Hydro One collects electricity charges and passes them to the IESO. These charges are used to cover the cost of electricity generation.
3.3¢
REGULATORY COSTS paid to the Independent Electricity System Operator (IESO) and charges to fund electricty support programs.
4.8¢
TAXES, which includes 8% rebate of PST portion of HST.
4.3¢
OTHER DELIVERY COSTS for line loss paid to generators, and a Smart Metering Entity charge paid to IESO.
6.3¢
TRANSMISSION
30.1¢
DISTRIBUTION
HYDRO ONE'S DELIVERY COSTS. This is the amount approved and allocated to build, maintain and operate 153,000 kilometres of powerlines, 85,000 steel towers and 1.6 million wood poles over its 640,000-square-kilometre service territory for its customers.
*Based on rates effective May 1, 2017 for a residential customer with a medium density service type using 1,000 kWh per month.

Where your Distribution Charges go…

15%
OUTAGE RESTORATION

70%
KEEPING THE SYSTEM RELIABLE
Replacing worn out equipment and trimming trees to keep power lines clear, maintaining a modern, reliable system.

15%
CUSTOMER SERVICE
Providing customer service by phone or online, providing tools so you can manage your energy use, ensuring accurate and timely statements.

What our customers told us

Our Application focuses on customer needs and preferences:

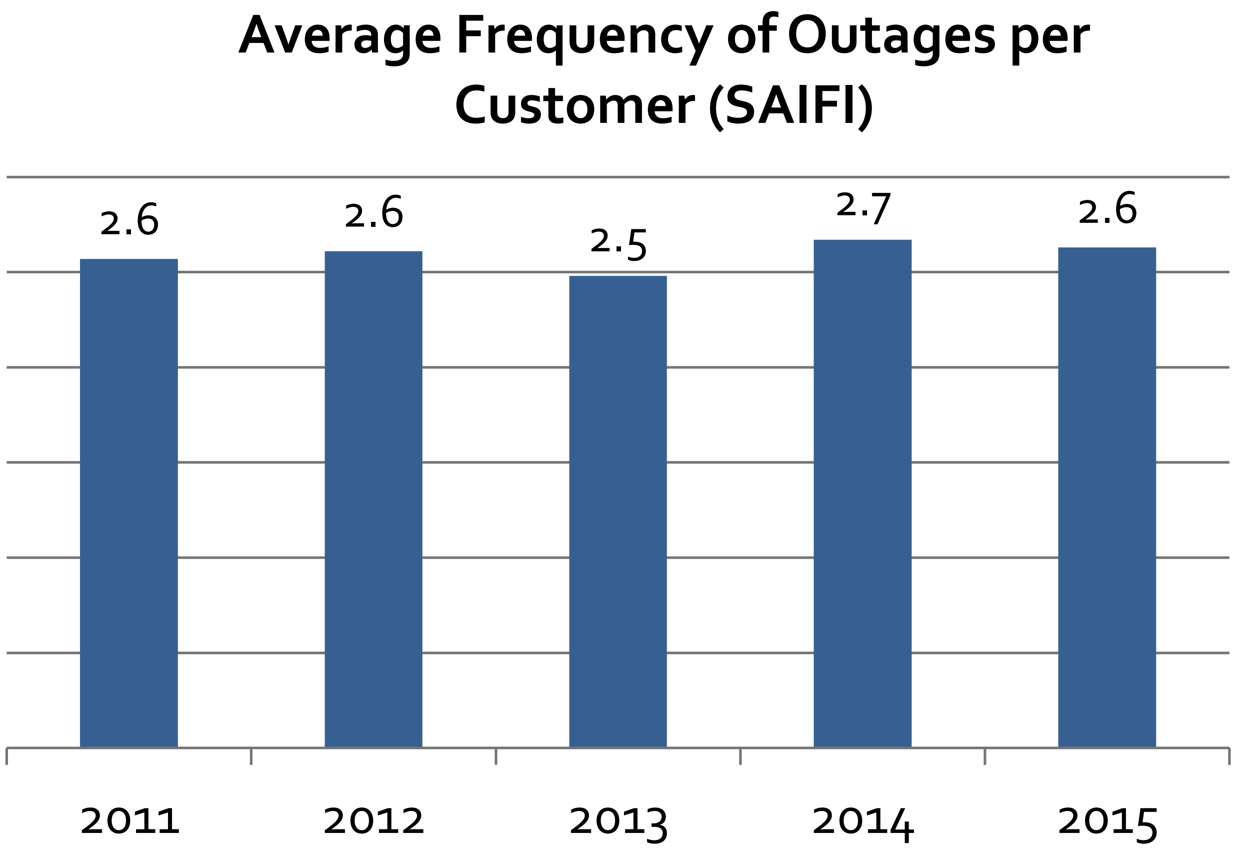
- **Keeping Costs Low**
  - *Keep costs as low as possible is customers' top priority.*
- **Maintain Reliable Service**
  - *Maintaining reliable electricity service is consistently second priority to cost.*
- **Large Customers**
  - *Large customers are more concerned with reliability and capacity.*
- **Manage Rate Impacts**
  - *Willingness to accept a rate increase to improve service level is limited.*

Hydro One's Rate Application

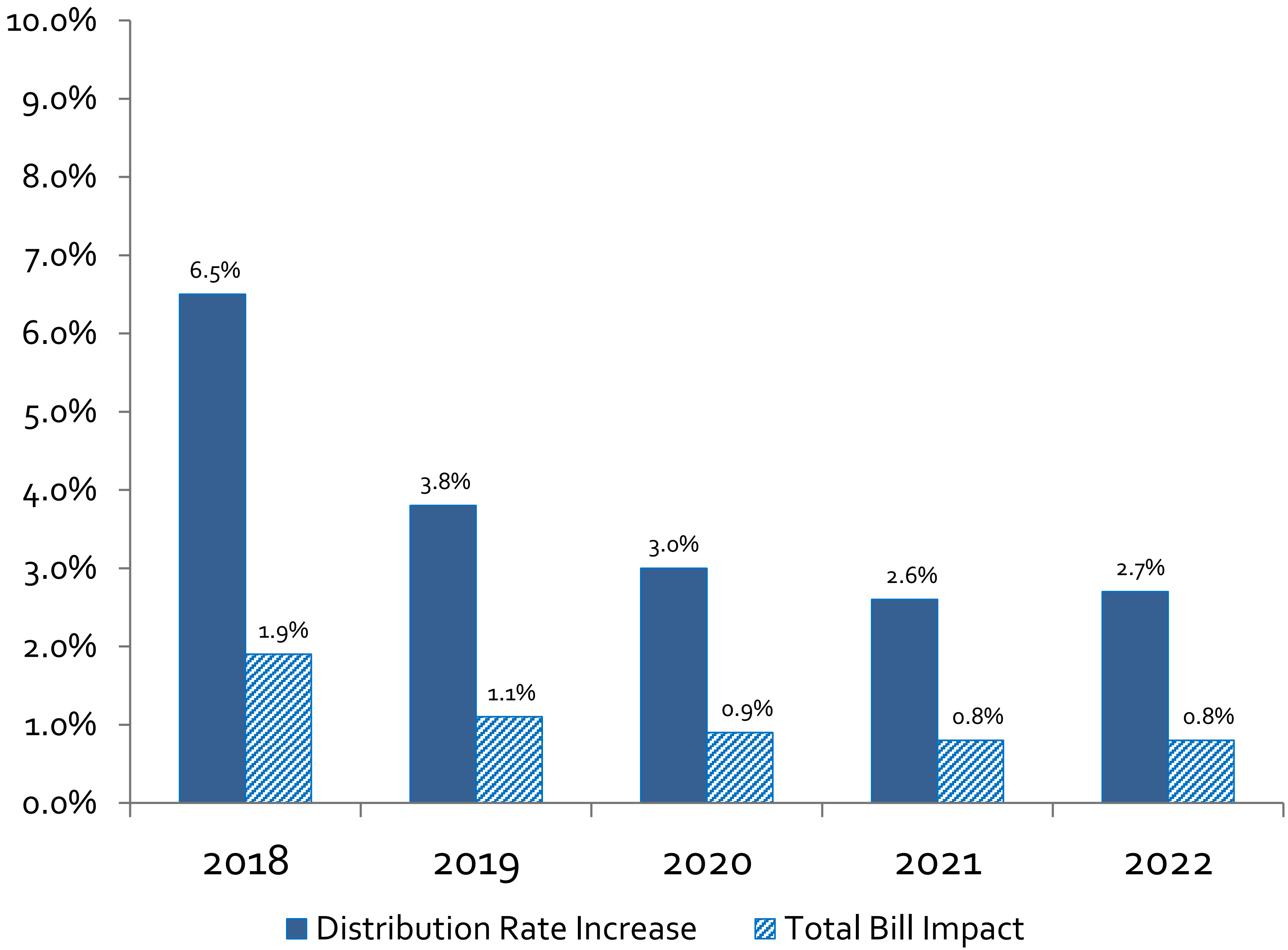
- Hydro One's rate application balances three considerations.

Hydro One's Rate Application – Asset Focus

- Hydro One's investment plan aims to maintain historic system reliability



Hydro One's Rate Application – Rate Impacts



Main Areas of Hydro One' Distribution Rate Increase

Cost Drivers	2018	2019	2020	2021	2022
Operations, Maintenance and Administration	-0.1%	0.5%	0.5%	0.5%	0.5%
Capital Related *(e.g., poles, wires, and transformers)*	2.0%	2.9%	2.6%	3.4%	2.5%
Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Load Impact	3.0%	0.2%	-0.2%	-2.3%	-0.3%
Other Revenue and Rate Riders	0.8%	0.0%	0.0%	0.6%	0.0%
Total	**6.5%**	**3.8%**	**3.0%**	**2.6%**	**2.7%**

About Load Impact…

- Cost of distribution services is spread out among all Hydro One customers.
- Total electricity consumption has declined since rates were last set.
- This contributes 3% to the average distribution rate increase in 2018.

Next Steps

- OEB to issue a Notice of Application and Procedural Order outlining the provisions in the proceeding.
- The OEB plans to hold some community engagement meetings about our Application.
- Individual customers or groups that represent Hydro One's customers can become an active participant (*Intervenor*) or an observer in the proceeding by applying to the OEB.
- Hydro One to submit an update to its Distribution Rate Application in June 2017 to reflect its audited 2016 actual costs.

Hydro One and Métis Engagement Session
Toronto Room, DoubleTree by Hilton
Saturday, May 13, 2017

SESSION REPORT

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WELCOME

[redacted], **Session Chair**, called the meeting to order and introduced Métis Nation of Ontario Senator Larry Duval, Moon River Métis Council. Senator Duval provided the opening prayer.

INTRODUCTIONS

The following individuals introduced themselves, and in some cases expressed an area of interest or concern:

Regional Councilor [redacted] Region #2:

President [redacted] MNO Northern Lights Métis Council: mentioned that he was looking for more information on Hydro One.

President [redacted] MNO Greenstone Métis Council: mentioned that he was looking for more information on Hydro One.

President [redacted] MNO Thunder Bay Métis Council: personal introduction

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: personal introduction

Sara Jane Souliere, First Nations and Métis Relations, Hydro One: personal introduction

President [redacted] MNO Ottawa Métis Council: stated that she was in attendance to listen and learn more about Hydro One.

Ms. [redacted] MNO North Channel Métis Council: personal introduction

President [redacted] MNO North Channel Métis Council: stated that she wanted to bring information on Hydro One back to the citizens of her Council.

Rhode Thomas, First Nation and Métis Relations, Hydro One

President [redacted] MNO Clear Waters Métis Council: mentioned that he looked forward to learning more about Hydro One and sharing that information with the MNO citizens.

President [redacted] MNO Peterborough and District Wapiti Métis Council: added at that he wanted more information on the work of Hydro One. He also wanted to identify ways that Hydro One could further include the Métis in the work that they were doing.

Chair [redacted] MNO Peterborough and District Wapiti Métis Council: added that she was here to listen and learn more about the work of Hydro One.

President [redacted] MNO Niagara Region Métis Council: stated that he wanted to learn more about the changes that were coming at Hydro One.

President [redacted], MNO Grand River Métis Council: stated that she wanted to learn more about Hydro One, any upcoming changes and to be able to share that with the citizens.

President [redacted] MNO Oshawa and Durham Region Métis Council: added that there were concerns about the costs of delivery to northern communities. She was at the session to learn more and bring that information back to the community.

Senator [redacted] MNO High Land Waters Métis Council: personal Introduction.

Tausha Esquega, First Nations and Métis Relations Team, Hydro One: personal introduction.

Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One: stated that it was a pleasure to welcome all to the session. His department, he explained, had the responsibility of First Nations and Métis Affairs and he looked forward to renewing those relationships.

Senator [redacted] MNO Moon River Métis Council: mentioned that he looked forward to learning more about Hydro One.

Regional Councilor [redacted] Region #7: mentioned that they were looking to advocate for lower hydro rates for their citizens as well and lessening the environmental impacts of tree cutting by Hydro One in their region. She also added that they are interested in obtaining information on procurement opportunities with Hydro One and that there is also a need to clarify the costs around Hydro delivery charges for cottages.

[redacted] **MNO Veterans Council and Captain of the Hunt, Region #7:** personal introduction.

Regional Councilor [redacted] Region #5: stated that he wanted to learn more about Hydro One and take this information back to his communities.

Denis Tremblay, MNO North Bay Métis Council: personal introduction.

Chair [redacted], MNO Matawa Métis Council: personal introduction.

President [redacted], MNO Sudbury Métis Council: personal introduction.

Rob Berardi, A/VP, Shared Services, Hydro One: personal introduction.

Kyla Thistle, Contract Officer, Supply Chain, Hydro One: personal introduction.

Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One: personal introduction.

[redacted] **Treasurer, MNO Sunset Country Métis Council:** personal introduction.

President [redacted] MNO Kenora Métis Council: mentioned they had a municipal hydro supplier in Kenora but many of his citizens were Hydro One customers.

President [redacted], MNO Superior North Shore Métis Council: mentioned that he had concerns around hydro costs as well electromagnetic fields. He also had some questions about the sale of Hydro One shares to First Nations and if this same opportunity was going to be provided to the Métis in the province.

President [redacted] MNO Credit River Métis Council: she introduced herself and mentioned that she hoped to learn more about new developments at Hydro One.

Regional Councilor [redacted] Region #4: stated that he was here to listen and provide input on Hydro One issues as they affect the citizens of Region 4.

Regional Councilor [redacted] Region ##3: personal introduction.

Daniel Charbonneau, First Nations and Métis Relations, Hydro One: personal introduction.

[redacted] **Director, Intergovernmental Affairs, Métis Nation of Ontario:** stated that the MNO has had a relationship with Hydro one for a number of years but not at this level. She stated that they could work together to make a difference and mentioned a forum that had been held to talk about procurement. Mr. Scott Patles Richardson was also working directly with Hydro One to address procurement initiatives.

Imran Merali, Interim Director, First Nation and Métis Relations, Hydro One: personal introduction.

Devi Shantilal, First Nations and Métis Relations, Hydro One: personal introduction.

MNO Vice-Chair [redacted] Provincial Council of the Métis Nation of Ontario: added that it would have been helpful to have the members of all their Consultation Committees here to learn and contribute to the conversations and maybe this could be considered for the future. There were also different Councils that could contribute such as the MNO Youth Council, the MNO Veterans Council and the Women's Secretariat of the Métis Nation of Ontario.

INTRODUCTORY REMARKS

Mr. Pugliese welcomed all the participants to the session on behalf of Mr. Mayo Schmidt, President and CEO of Hydro One, and also his colleagues present at the session. He thanked Senator [redacted] for his prayer and acknowledged the traditional territory of the Mississaugas of the New Credit First Naiton. He mentioned that this was an opportunity for dialogue and that they were here to listen and take that information back to Hydro One. He explained that this was not the last gathering but rather they would like to do this on an annual basis. They also hoped that they would have the opportunity to meet with the councils as well. He introduced himself with some background information.

Mr. Pugliese continued by providing some background information on Hydro One including an overview of how Hydro One interacts with First Nations and Métis communities across Ontario. He said that there were many misconceptions of the work of Hydro One and there was a need to communicate more with Ontarians around this. They were not responsible for power generation or for rate setting; however they were responsible for power distribution. He said that they have been undertaking this education piece.

In terms of privatisation, he explained that one year ago the government decided to sell the assets of Hydro One and now Ontario holds about 49.9% of the shares; Hydro One had transitioned to a private company.

As the company changed direction from a Crown corporation to a public company, there was an opportunity. In this shift there were two (2) things they had embarked on:

- The first was education, to help explain Ontario's complicated electrical system including the regulators, etc. Hydro One has started to uncover what can be addressed and asked for the opportunity to first understand and then work on the things that they can change.
- The second task was related to advocacy. Hydro One owned the hydro bills and maintained relationships with communities and customers. Hydro One had an impactful voice in advocating of behalf of its customers.

Mr. Pugliese reiterated that the session was not designed to be a consultation rather it was the first step in a series of discussions that would lead to change. He also recognized that change is indeed required, particularly in the area of affordability.

Hydro One staff here at this session would be providing presentations that focused on customers and communities. Hydro One wanted to hear how people thought Hydro One could make Hydro One a better company, as this would give them an opportunity to grow Hydro One. He said that Hydro One was hoping to be a good model for privatisation in this country. Hydro One hoped that they could build their strength on how they interact with Indigenous people everywhere.

In terms of First Nations and Métis relations, Hydro One viewed them as more than partners, he explained, as they were integral to their business relationships. He stated Hydro One would like to see the corporation at the forefront on these types of relationships; he understood that they did this well in some cases but there was room for improvement. Partnerships meant procurement opportunities, employment opportunities and capacity building.

Hydro One has assembled a new executive team and launched a number of cost saving initiatives. Hydro One was also looking at growing the business in the area of advocacy and education as well. In terms of education initiatives, Hydro One wanted to inform the public about the mandate of the Hydro One in terms of power delivery versus generation and the issues around the rates. He stated that 37 cents on each dollar could be attributed to Hydro One's transmission and distribution system while more than 50 cents on the dollar came from power generation. The 37 cents is an average, and it is for each dollar collected on the bill. In terms of advocacy, they were looking at opportunities for advocacy on behalf of all communities to the regulators and mentioned the example of addressing the distribution rates. He explained that the rates are impacted by population density and infrastructure costs in rural areas. He also explained that they would be looking at rate reduction coming into effect in September this year. Hydro One played an advocacy role on the First Nation shares and provided information to the Ontario Energy Board on this matter.

They have made a number of changes over the past two years, Mr. Pugliese explained, including changing the winter moratorium to June 1. Hydro One has also reconnected a number of customers while waiving the reconnection fee. For those in arrears, they have been working on building a new collections program and currently 60% of those who have been disconnected or were in arrears are in new affordable payment plans. Hydro One has been working with community members to identify any issues with their bills and establishing payment plans and Hydro One was working with administrators on supporting community capacity building. Hydro One was shifting their view as a company and reaching out to customers to address their concerns, solve problems and be more accessible. Hydro One was looking at new approaches and this session was an example of that. Hydro One is looking for feedback on updating Hydro One policies going forward.

Senator [redacted] asked if the hydro rates would be lowered for rural areas. Mr. Pugliese stated that they were always looking for the best ways to use their assets and their customers would see significant reduction starting in July or September this year upon implementation of the Fair Hydro Plan

Regional Councilor [redacted] stated that they would like to see more procurement and employment opportunities for their citizens. One of the issues with employment related to housing in her region; individuals could not move to an area to work for Hydro One if there was no housing available in those communities. Mr. Pugliese noted that this was a complex issue and they needed to think this through with their procurement unit. He acknowledged that they could not solve all the issues but they needed to look at what opportunities could be identified.

President [redacted] asked if this new hydro distribution reduction plan meant that there was one flat rate for the province. Mr. Pugliese stated that essentially this was true - 2/3rds of the province was rural and paying higher rates but now this will be equalize, but those paying lower rates will not be seeing higher rates. He stated that the rural rate will be lowered to match the urban rate and they will do this using the existing tax base; this was a policy decision.

Regional Council [redacted] asked for a definition of “rural” and “urban”. Mr. Pugliese stated that an upcoming presentation will provide this information in detail.

[redacted] referred to Mr. Pugliese’s update on the future expansion of Hydro One and asked if this meant delivery to the United States. She also asked how they would look at servicing areas in Northern Ontario that did not yet have service. Mr. Pugliese stated that in terms of expansion, there was wide spread potential across Canada, North America and across the world but they understood that there was still work to be done here in Ontario. He explained that they had bid on the work for the East-West Tie but were not successful; they were looking for opportunities to partner in order to expand. They were also looking for these kinds of partnerships with First Nation and Métis communities. He stated that Hydro One saw the need to build up more in Ontario and they were committed to doing that.

President [redacted] asked if they would be talking about Hydro One employment. She stated that they had citizens that have graduated and were having trouble entering Hydro One’s employment programs, such as the apprenticeship programs. She asked if there was an employment coordinator that could assist them with the process. Mr. Pugliese said that they would discuss this in more detail later on in the day but he realized that they still had a lot to do in this area. They have to work with Unions to increase the number of apprenticeships. They are working with their Human Resources group to make those changes. He said that they have not done particularly well in this area but they needed to track and report on any progress in this area. President [redacted] stated that it was disappointing to hear that this process was just starting. Mr. Pugliese stated that there were parts of Hydro One where this had been done well and there were a lot of students and apprentices but there were areas that still needed to be addressed.

[redacted] stated that he was concerned that the reductions in bills now may mean a big increase in the future to make up for it. Mr. Pugliese stated that they were not here to defend this policy change, but that he would say that the increases in green energy generation have caused changes, which have meant there had to be cost adjustments as this system was a cost recovery system. He said that they had spread the costs related to the rate reductions over the life of the assets and depending on how those contract renewals were negotiated, he did not believe that there would be an escalation. He explained that if the contract remained unchanged, the consumer would likely see those escalators. It was important, he added, that they asked those questions and understand the facts.

President [redacted] asked about recouping those losses of funds with those reductions, as Hydro One was a business now. She also asked if the northern consumers have been overcharged all this time and if there would be a retroactive rebate for that. Mr. Pugliese stated that Hydro One did not set the rates; those rates were established by the Ontario Energy Board. He explained Hydro One prepared a submission to the OEB to outline what their costs would be to provide the distribution of the energy; this was what they needed in order to do their work. The OEB could approve this work plan and then Hydro One started spending to get the work done. The rate reduction was a result of the government decision and this was being funded by the government, not Hydro One. The costs to cover this reduction would come out of the Ontario tax base. In terms of an overcharge to northern consumers, Mr. Pugliese stated that they did not look at the rates this way, it was a policy maker's decision and it was not seen as an overcharge; it was a cost recovery system.

Regional Councilor [redacted] stated that, in terms of the East-West Tie, there were eleven Métis communities impacted by that work. He suggested that the Hydro One bid to undertake this work should have included the Métis and that Hydro One should have a Métis Relations person on staff that was familiar with their governance structure and processes. Mr. Pugliese thanked him for his comments and stated that their submission for the East-West Tie was submitted in 2014 and he realized that they should have included others; they intended to change that approach as they went forward.

President [redacted] asked about the possibility of using more non-wood poles for the lines, as this would save more trees. Mr. Pugliese stated that Mr. Jesus would speak to this later today but he understood that non-wood poles were significantly more expensive than wood.

[redacted] stated that Mr. Pugliese had mentioned that they needed to inform themselves with the facts regarding energy in Ontario and she asked where they could go for this information. Mr. Pugliese responded that they could call Hydro One at any time or consult their website where there was a lot of information on energy policies in Ontario. He added that they had a lot of experts that could come to the community and spend some time providing the information they required. Hydro One, he explained, was a neutral party and could provide impartial information, advocate as required, but they needed partners in that advocacy role.

Senator [redacted] stated that they received a 10% discount from province for their hydro bill and he asked if this would be removed because of the upcoming rate reductions. Mr. Pugliese said that this sounded like the R1 adjustment and the HST and he said that this would be unaffected by the upcoming rate reductions.

Mr. Pugliese ended this part of the presentation with a video outlining the changes in Hydro One and their purpose of "turning on the power of possibility". It was noted that Hydro One welcomed feedback on the video.

CUSTOMER SERVICE

Mr. Imran Merali, Hydro One, provided an overview of his PowerPoint presentation entitled "Customer Service". He asked for views on Hydro One customer service.

The following comments were provided by the participants:

- [redacted] mentioned that when she has had to call Hydro One, she was transferred a number of times to different people. She suggested that they need to have a better idea who to direct which calls to.
- **Regional Councilor** [redacted] agreed stating that he has called about his hydro bill and the person answering the phone was unable to answer his questions. He stated he had a question about usage when he was not in residence.
- **Regional Councilor** [redacted] mentioned that she had began her inquiry in French and mentioned that the French provided was not Canadian French but rather Parisian French. She also mentioned that she had shut off everything at her cottage and then was told she should have shut off her breaker and since she was six hours from her cottage, she had to get someone to go there to shut it off. She never received a follow up call from Hydro One to say it was shut off.
- **President** [redacted] had issues with how much power was used in a residence that had everything shut off. When she called about this, she was told to wrap her hot water heater but the hydro costs continued to rise. She was not sure why her hydro bill would be higher than her neighbours and could not get a satisfactory answer on that from Hydro One.
- [redacted] asked how often Hydro One conducted house calls. Mr. Merali noted that these were frequent and Mr. Jesus could provide more detailed information. Ms. Clarke suggested sending an email with a photo of the technician, as she had seen this done with some other companies and it was a useful tool.

Mr. Merali thanked them for their comments and stated that, at Hydro One, all staff were responsible for customer service. Hydro One was anxious to hear the feedback of their customers and looked forward to improving their practices. He provided an overview of the Flip the Switch campaign, which was designed to solicit the views of their customers and make the policy changes to address their issues. One of the actions they have taken was inviting all their Executives to take calls in their call centre so they could learn more about customer concerns and then to go back to their sections and make the necessary changes. He provided a video to show this.

He provided an overview of the some of the transformational changes they were already making and provided an overview of the vision of Hydro One. Some changes included opening their call centre on Saturdays and increasing the support electronically as not all issues needed a verbal exchange. They want to be easy to do business with and increase their work on education, advocacy and responsiveness. He spoke to the importance of education and ensuring that their customers knew what Hydro One was responsible for and what was not their responsibility. Mr. Merali provided an overview of the Fair Hydro plan, which meant significant rate reductions through the reducing of the global adjustment charge and lowering the delivery charge for rural customers including eliminating the delivery charge for on-reserve customers. He stated that they would see a reduction of their hydro bills this summer with the average bill being reduced by 33%.

Regional Councilor [redacted] noted that they had not had a discussion on eliminating the delivery charge for those customers on-reserve. Mr. Merali explained that the First Nations leadership, through the Chiefs of Ontario, advocated for the elimination of this charge and Hydro One had supported that. He said that nothing similar existed for the Métis in Ontario. The Regional Councilor stated that they had not even had an opportunity to have that discussion. Mr. Merali explained that this discussion was not initiated by Hydro One and if the Métis wanted to lobby Ontario for something similar, Hydro One would support that as well. When asked why it did not automatically apply to the Métis, Mr. Merali explained that it currently only applies to residential properties on-reserve. Regional Councilor [redacted] stated that they would need to follow up with the province on this issue.

Mr. Merali continued with his presentation providing an example of a customer bill explaining that there would be significant saving on bills such as this one, which was rural density and high consumption.

President [redacted] asked if these reductions were for individuals only or also for businesses. Mr. Merali clarified that this applied to individuals and small businesses but the delivery charge reduction was only for residential customers. The most significant was for rural residential customers who would see a reduction of approximately 40% on their hydro bill.

Regional Councilor [redacted] asked about how they defined "rural" versus "urban" and what the formulas were in figuring out rates. Mr. Merali explained that this was defined by the OEB and more information could be found on their website. Essentially it involves how many people lived in a geographic area and the number of customers per km of line.

President Trent [redacted] asked about distance from power generation facilities mentioning that he lived approximately 400 yards from a 4500Mw hydro plant and he was paying very high delivery rates. Mr. Merali stated that when the OEB set the rates, it was the same no matter where they lived within a certain geographic area and, until now, rural residents paid more no matter where they lived. Mr. Oded Hubert, VP, Regulatory Affairs, stated that North America has a very large power grid and the hydro any individual might receive, might not come from close to them; they needed to depend on the entire structure for reliability.

Regional Councilor [redacted] asked how he would describe the density zone and how defining those areas were arrived at. Mr. Hubert stated that this was defined in a manual way previously by Hydro One staff (counting houses, kilometres of line, etc.) but now Hydro One was using a geographic information system to assess density and male these determinations. "

Mr. Merali continued on with his presentation providing an overview of the revised customer relief program. He explained that effective April 25, 2017, Hydro One was providing additional relief to assist customers that had accumulated significant balances on their accounts during the winter. He provided an explanation of a number of policy changes in this area. Hydro One was also making a number of customer commitments including the introduction of service guarantees. One of these was an automatic $75 credit for missing appointments they had booked in residences and also if they did not hook up their hydro by the time five days had passed. Hydro One was also introduced a new hydro bill and maintaining their record of very high bill accuracy.

Senator [redacted] asked about the estimate that is sometimes part of his bill, which caused some issues when the bill estimate was very low and then very high. Mr. Merali stated that they wanted to read the meters on a monthly basis to avoid these estimates and they could also set up budget billing, which meant they could set the bill based on a monthly estimate and this would be reconciled at the year's end. There were a number of new tools and technology for their customers to use to report their meter reading.

Mr. Merali provided an overview of all the ways they communicate with their customers including increased use of e-billing, high usage alerts, new website with customer portal and the redesigned bills.

[redacted] asked if Hydro One had looked at an incentive for customers to sign up for e-billing such as an eliminated administrative fee. Mr. Merali stated that they did not charge for paper billing so there was no change for e-billing but they were looking at a campaign to increase the use of e-billing. Ms. Clarke noted that incentives could give people a little more money in their pocket that could applied during the winter months.

President [redacted] asked about the effectiveness and quality of the smart meters that were installed, as some in the Sudbury area felt their hydro costs went up at this time. Mr. Merali said that the consumption was unchanged with the arrival of the new smart meters; he suggested that this may have coincided with government change of pricing for hydro during this same time.

[redacted] suggested that Hydro One had cut down a number of trees in the North Bay area to avoid interruptions due to weather but they had not cut down the right trees. Mr. Merali stated that he would be happy to follow up on this off line and check into this. In addition, Mr. Jesus would be adding additional information on hydro reliability later in the day.

[redacted] asked if Hydro One played any role in addressing the issue with door to door energy contract sales persons. He also asked if those locked into those contracts would see any rate reductions. Mr. Merali stated that Hydro One has no role to play with those outside companies but the Hydro One website has information on how to compare costs. He did not know if there were rate reductions on retail contracts but he agreed to follow upon on that.

HYDRO ONE DISTRIBUTION RATE FILING (2018-22)

Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One Mr. Hubert described how Hydro One is seeking approval from the OEB with a distribution rate application that will provide the revenue required to operate the system for the next five years (2018-2022). This is the standard application that Hydro One now has to complete every five years. Hydro One has filed with the OEB a significant amount of information to make their determination, including the proposed rate increase and total bill impact. The Premier asked Hydro One, among others, for advice on providing relief to rural customers, given that the delivery charge is often higher than the usage charge. Mr. Hubert provided an overview of Ontario's Electricity system including how the electricity flowed from the generators to the customers in Ontario. President Yvonne Jensen asked why a transformer would ever blow up.

Mr. Hubert stated that this could be caused by an electrical fault, lightning, a manufacturing flaw or a malfunction within the system. Mr. Jesus explained that some assets were getting older and there could be some insulation defects internally. Transformers had a 40-50 year life span with poles lasting a little longer. Mr. Hubert added that asset monitoring took place over the life of the asset. When asked if this was dangerous and about PCBs, Mr. Hubert explained that there might be a small oil spill and there were fewer transformers with PCBs because they are being replaced. In accordance with federal legislation, these would be all removed by 2025.

[redacted] asked if she was buying a home and this type of oil spill had happened from a transformer, would she be informed of that. Mr. Jesus said that this would have to be reported to the federal government but the information might not necessarily get to her as the homeowner. Mr. Hubert explained that regulations are in place around who had to be informed. Ms. [redacted] asked if she was selling her house, she would need information on how the cleanup was done. Mr. Hubert stated that this was out of his area of expertise but they could follow up on that question and get back to the MNO on that.

Mr. Hubert continued with his presentation providing an overview of the Hydro One distribution system and Ontario regulatory framework. Distribution rates are set by the OEB and he explained that their application was filed with the OEB on March 31, 2017. The public hearing process was about to begin. He provided an overview of the breakdown of the electricity costs to customers.

Christa [redacted] asked if environmental costs were included in the 51% of the bill that covers commodity costs and Mr. Hubert stated that it was and the generators are accountable for the costs in this portion of the bill. This includes costs to provide the service today but it may also include a provision in consideration of the implications for the future.

President [redacted] asked for an explanation for the reference of loss of power on his hydro bill. Mr. Hubert mentioned that this was covered in the "Line Losses" at 4% on the graphic and this was in reference to power that was lost in transit. Generators have produced the power and therefore must be paid for it, and Hydro One has to account for any power loss and as long as the transmission and distribution were done as efficiently as economically possible, they could expect to recoup this loss. Mr. Hubert was asked where they would get the incentive to make efficiency improvements when they received compensation for their losses. He responded that this came in up in the OEB hearing as well and that Hydro One seeks to reduce losses where it is economic for it to do so in the areas under its jurisdiction.

Senator [redacted] asked about the forestry work that needed to be done to cut back trees from the lines and if this work would be undertaken by contract workers or Hydro One workers. Mr. Hubert said that they would use a mix of external and internal workers for that.

[redacted] asked about the new rate application and if there would be increased costs related to security. Mr. Hubert stated that they do take this into consideration and there were international standards for reliability and this included critical infrastructure protection. This also included protecting the copper in their equipment.

Regional Councilor [redacted] asked about species at risk legislation when it comes to cutting trees down to protect the lines. In the past, they were told that there was no budget for mitigation in these cases. Mr. Hubert mentioned that he was not sure in that case; for larger projects they needed to undertake an environment assessment. He said that he would have to follow up with MNO on this particular question.

[redacted] asked about options for putting their lines underground in the future. Mr. Hubert stated that the main issue was costs; this might be economically possible in urban areas but cost prohibitive in rural areas. Mr. Jesus stated that this would cost 10-20 times more than the construction of overhead lines.

Mr. Hubert continued with his presentation outlining where the revenues collected for distribution are spent and invested. He said that 70% went to keeping the distribution system reliable, 15% went to outage restoration and 15% went to customer service. Customers had told Hydro One that keeping costs low was the top priority and maintaining reliable service was the 2nd priority. He stated that this means “maintaining” the current level of reliability, as improvements would involve raising the current costs. He asked for the participant’s feedback on these priorities.

Regional Councilor [redacted] stated that this was a challenging situation in terms of costs as the Metis would likely agree to lowering costs as a priority but would not want this to impact on their traditional way of life. She felt that this was something they, as Metis people, would likely want to discuss in more detail.

Mr. Hubert continued with his presentation explaining the rationale of their rate application to the OEB considering customer needs, asset needs and rate impact among others. While the government's Fair Hydro Plan may result in bill reductions of approximately 30-40, it was Hydro One’s job to complete the submission ensuring that they received enough funds to keep up the needs of the distribution system. He provided an overview of the costs that were included as part of the application for 2018-22 which showed an increase in the areas of operations, maintenance, capital related costs, taxes, load impact and other revenues and rate riders. The largest increases were in the areas of capital infrastructure costs and load impact adjustment over the next four years.

[redacted] asked about the impact of the changes to alternative power within the province. Mr. Hubert said that many that were producing alternative power for the grid are not using this in their own homes but were selling it back to the grid. These individuals were still accessing power from the grid. He said, when looking at their rates, the customers wanted

Hydro One to look for increased productivity and efficiencies before coming to the customer with higher rates to cover the costs and they did this before hydro one make their rate application to the OEB.

Regional Councilor [redacted] asked if there was anything in the five-year rate plan that addressed the ring of fire development with the Province of Ontario. Mr. Hubert stated that this was not part of this proposal as Watay Power was working on this; this application is specific to distribution rates.

[redacted] asked about possible escalated costs in the future (post 2022) based on the budget here on the distribution side. He asked if this could have an effect on individual bills. Mr. Hubert stated that this could have an impact depending on the commodity price; a government initiative would have to be sought to offset those costs.

Mr. Hubert continued outlining the next steps in the OEB application process. The OEB would issue a public notice about the application and then there would be public hearings. Individual customers or groups representing Hydro One's customers could become intervenors in that process or they could be observers.

Regional Councilor [redacted] asked what their status as Metis people would be within the hearing process. She asked if they would return to this process to feed into those OEB hearings. Mr. Hubert stated that this session was not part of that consultation process; it was an engagement initiative. He also said that the intervenor process completely handled by the OEB. He suggested that if MNO wanted to participate in the OEB hearings, they needed to register with the OEB. Regional Councilor Richardson made it clear that they had Aboriginal rights that did not fall under OEB regulations. She said that they told their people not to participate in those processes as they were a right bearing people and they had a process for consultation already in place through their internal structures. Mr. Hubert stated that he would defer to the First Nations and Metis Relations section of Hydro One to comment on that. Mr. Charbonneau stated that this was not their process but rather OEB's and Regional Councilor [redacted] asked if the OEB was the Crown in this case. Mr. Charbonneau was not sure as he could not speak on behalf of the OEB; he was unsure if the OEB could trigger the duty of consult. It was suggested that the MNO would have to go to the Minister of Energy to address this, as this has not been delegated to Hydro One. Regional Councilor Richardson stressed that she needed some information on where she should go to follow up on this important question.

OPERATIONS – HYDRO ONE RELIABILITY MEASURES

Mr. Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One, provided an overview of his PowerPoint presentation entitled "Reliability Performance Overview". He said that he would be looking at the distribution and transmission systems and how Hydro One was directing investments to maintain reliability. He provided an overview of the customer engagement initiative which took place in 2016 and conducted by a third party. The focus of response had asked Hydro One to keep the hydro costs as low as possible with the second priority being reducing the number of outages.

Mr. Jesus provided an overview of the process to get the electricity from the generator to the customer. He mentioned, in response to the question earlier in the day regarding non-wood poles and he stated that these poles were very costly compared to wood poles, from 10 to 20 times the cost. His presentation concentrated on the transmission and the distribution systems and addressing reliability within those systems. In terms of the transmission system, the primary cause of interruption was weather and equipment failure. There was a marked difference in the reliability of the system in the north and the south. Hydro One was maintaining reliability in the transmission system by increasing capacity investments (lines), leveraging technology and reducing planned outages by bundling work among other initiatives.

[redacted] asked about the impact of solar flares on hydro reliability and also if they would be able to access power from other jurisdictions (other provinces or the United States) if needed. Mr. Jesus replied that they had built a system to address the possibility of geomagnetic outages. He said that they did have those connections to other jurisdictions but Hydro One was really seen a leader in terms of hydro transmission and distribution.

President [redacted] said that they had many power surges in their area and she asked about the cause of this. Mr. Jesus said that he could not speak specifically to her situation so they could talk offline about that but generally there were a number of possible causes including weather, an issue with the line among others.

Regional Councilor [redacted] asked how often Hydro One flew over their lines. Mr. Jesus said that there were regulations they had to adhere which stated that they had to every two or three years. Regional Councilor [redacted] also asked about AC and DC lines. Mr. Jesus explained that DC lines were normally used for great distances but they did not have DC lines anymore; they had a DC connection with Hydro Quebec and they were proposing a DC connection to Pennsylvania. To convert lines from AC to DC was costly and it was not seen as necessary in the distances they were talking about.

Mr. Jesus continued with his presentation stating that the primary causes of interruption in the distribution system were from tree contacts and equipment failure.

President [redacted] asked if new research has gone into non-wood poles. Mr. Jesus stated that the poles were mostly wood still as it was more expensive to use non-wood poles. He did say that they were looking into other technologies in some areas but steel was cost prohibitive.

Regional Councilor [redacted] asked what the wood poles were treated with and it this could negatively affect vegetation in the area. Mr. Jesus was not sure and he stated that he could follow up on that and get back to the MNO.

[redacted] asked who owned the poles in rural areas. Mr. Jesus said that Hydro One owned these poles up to the property line of the individual; the owner was responsible for the poles on their own land. Mr. Hubert noted that if a customer had to bring in the electricity to their own home, they do get some credit for distribution and do not necessarily have to pay the full costs of installing the lines to serve their property. These stipulations were all laid out by the OEB.

Regional Councilor [redacted] asked what would be the reasons for interruption if the copper was stolen by a thief. Mr. Jesus stated that this would likely be under equipment failure or possibly unconfirmed cause.

[redacted] asked if Mr. Jesus has ever heard of smart meters catching on fire. Mr. Jesus did not think this could happen. Mr. Pugliese mentioned that there was a story in the news where the face of the meter caught on fire but the fire itself was not caused by the meter. If, in the future, there was an issue with the meter, Hydro One would address that.

Mr. Jesus continued with his explanation of the distribution system stating that there were longer outages reported by customers in rural areas but it was difficult to find the outage. For this system, it was not a smart response system as they depended on customers notifying them of where the outage had occurred. Hydro One recognized that the reliability in these areas was not very good and they were working towards improve that by leveraging the meters to show the outages so the crews find the outage cause and location. This was all being done to minimize the impact of the outage on the customer. He outlined some programs they were undertaking to maintain reliability in the distribution system such as the renewal programs to replace aging equipment.

President [redacted] asked if power outages were identified by the length of time the power was out, as some were just out for a few seconds. Mr. Jesus said that those less than one minute was a momentary outage and sustained outage was more than one minute.

EMPLOYMENT – OVERVIEW OF HYDRO ONE ABORIGINAL EMPLOYMENT AND TRAINING

Devi Shantilal, First Nations and Métis Relations, Hydro One provided an overview of the Employment and Training presentation. She explained that no one Hydro One Human Resources was in attendance at the meeting and that if she could not answer questions raised, she would follow up after the meeting. She explained that Hydro One was committed to providing employment and training opportunities through apprenticeships, co-ops and internships.

[redacted] asked for information on the percentage Métis employees at Hydro One, including the percentage in management or senior positions. Ms. Shantilal indicated that the numbers are based on voluntary identification and committed to follow up on finding this information. She added that there were on-going diversity support systems for example was an internal women's network within Hydro One and that Hydro One was looking at launching additional initiatives to support various diversity groups to focus on awareness training and other issues. She further noted that that Hydro One has a diversity consultant and there are ongoing efforts at the senior management level and they were looking at initiatives for supporting Aboriginal employees. Ms. [redacted] suggested using the terms "First Nation, Inuit and Métis" rather then "Indigenous" or "Aboriginal" as people generally did not like the umbrella terms. Ms. Shantilal acknowledged this request and added that Hydro One used the phrase "First Nations and Métis Relations training" and they sometimes use the terms "Indigenous" or "Aboriginal" in existing material but they would look changing this terminology. Ms. [redacted] asked if the Hydro One was addressing the recommendations of the Truth and Reconciliation Commission recommendations. Mr. Pugliese stated that they did and they were looking at taking this further to ensure that all leaders in Hydro One had an enhanced level of cultural awareness. There are 50 plus leaders to go through this training, which would immerse them in all issues.

[redacted] asked about the interview techniques of Hydro One, as many First Nation, Inuit and Métis persons were more visual in terms of a communication style. She recommended using different interview techniques and not just the standard format in order to be responsive to different ways of learning. Ms. Shantilal indicated that when she went through the process, there were a number of different styles used that would allow individuals with different strengths to use that opportunity to showcase their strengths but she would follow up with Human Resources to find out more on this.

[redacted] asked what was involved in Hydro One's Aboriginal cultural awareness training and where did the information come from. Ms. Shantilal stated that the information used in the training comes from various sources, including the MNO website. The request was made by MNO representatives to see the material used in the Aboriginal awareness training. Mr. Merali indicated that Hydro One was in the process of refreshing their training and they welcomed feedback on the new training package. Ms. [redacted] indicated that MNO would be pleased to review the training package and they could also provide training and perhaps make it more interactive. Ms. Shantilal stated that they could discuss this.

Regional Councilor [redacted] stated that any region could provide this cultural awareness information and that they could work in partnership; he invited Hydro One to come meet with them and their knowledge holders in the regions. He also asked how their hired for promotions and if they focused their efforts on this from within their organizations. He also asked where their training facilities were. Ms. Shantilal indicated that she did not have the information regarding promotions and that she will follow up with their Human Resources section at Hydro One. In terms of training facilities, she indicated that she will put together a list of training facilities and forward that to Ms. [redacted] for distribution.

Regional Councilor [redacted] asked if Hydro One had any Métis employed in the First Nation and Métis Relations. She noted that Hydro One leadership recognized the territory of the Mississaugas of New Credit but did not recognize that this was also the territory of the Metis. She stated that the Aboriginal awareness training they were providing needed to specifically recognize the Métis, as well as the First Nations. She made the point that if they were building a relationship, Hydro One needed to recognize the perspectives of the Métis of that particular territory. She stated that MNO Employment and Training (MNO-ET) was obtaining funding to help them develop their training/awareness programs and that MNO-ET staff should be part of this discussion. She added that when Hydro One went into a particular region they need to realize that it was not only what could you give the Métis but they also had something to offer. Ms. Shantilal thanked the Regional Councilor for her comments and recognized that this meeting was also on the Métis homeland and that Hydro One recognized the need to be more inclusive. She further stated that this was a relationship building meeting and they appreciated these comments.

[redacted] suggested that Hydro One be mindful that most Métis communities do not have a land base and that eligibility for PowerPlay projects should be open to Metis communities; most eligibility requirements are not inclusive to Métis communities. Ms. Shantilal indicated that, when designing or renewing their programs, they would keep this in mind. Mr. Pugliese further stated that there was a lot of programs that were under review and that Hydro One would be acting on the feedback provided.

[redacted] stated that Union Gas had goal for First Nations, Inuit and Métis recruitment and Hydro One should have a goal if they did not have this in place already. Mr. Pugliese responded that Hydro One will establish a goal and they will be tracking it.

President [redacted] asked about the updating of the Aboriginal awareness training modules, and if, once completed, the Hydro One staff will be retrained on newly updated information and the response was in the affirmative.

[redacted] reiterated some of the things that have been mentioned to potentially increase employment targets such as posting jobs on the MNO website, involve the MNO-ET in discussions involving scholarships, among others. Ms. [redacted] also stated that the MNO did a lot of training and they could also assist Hydro One in this regard. She indicated that the MNO had been working with Hydro One on procurement issues such as hosting an event for Métis businesses to learn more about procurement opportunities that might exist.

In closing, Ms. Shantilal thanked all participants for their feedback and for the offer to help Hydro One with the Aboriginal awareness training and looked forward to more discussion on that.

PROCUREMENT – OVERVIEW OF HYDRO ONE ABORIGINAL PROCUREMENT PROCEDURE

Rob Berardi, A/VP, Shared Services, Hydro One, provided an overview of his presentation entitled "Aboriginal Procurement: Doing Business with Hydro One". Mr. Berardi opened his presentation by thanking everyone for attending this session and also introduced Kyla Thistle, Contract Officer, Supply Chair, Hydro One, as his co-presenter. He provided a review of current Hydro One procurement procedures. He also stated that they could attend MNO regional meetings to discuss how to navigate the Hydro One system on procurement.

[redacted] asked if Hydro One identified a certain percentage of money aside for First Nation, Métis and Inuit procurement. Mr. Berardi responded that Hydro One did not put a specific percentage aside right now but they could look at doing that. Hydro One did about $15M per annum in Aboriginal procurement right now and they wanted to increase that by 20% each year.

Mr. Berardi explained that Aboriginal participation was preferred and they had information on their external website and competition was limited to qualified aboriginal business. Some contracts could be directly awarded to qualified Aboriginal business. Hydro One could do things differently than when they were a crown corporation.

Regional Councilor [redacted] made the point that a lot of the focus was on supply and purchasing but what about when they were decommissioning assets. Mr. Berardi responded that Hydro One bought things but they also bought services. In terms of decommissioning assets, a supplier could review the asset and then provide the services required for that.

Regional Councilor [redacted] noted that a lot of the issues around Union positions and contract work. He explained that many Métis businesses were small businesses and did not involve unions. Mr. Berardi indicated that it was a difficult question as labour relations have jurisdictions in certain areas such as construction zones or transmission stations. He acknowledged that Hydro One and MNO needed to have those discussions and that Hydro One was open to that. Regional Councilor [redacted] indicated that Union Gas had a stipulation that if they are going to work there, the reserve could provide their own non-union workers. Mr. Berardi stated that those were issues for discussion with labour relations but that there are a lot of services that were non-unionized and these contracts could be filled by Métis businesses.

Mr. Berardi continued his presentation by provided information on the types of materials and services purchased, including heavy-duty equipment, road construction, aggregate and concrete, etc. He explained that there were six steps to award contracts. He suggested that they might want to focus on getting businesses registered and then look what was available. He stated that they could come to the regions to show business owners and others how to get registered and go from there.

[redacted] asked if Hydro One purchased food services. Mr. Berardi responded in the affirmative; Métis food services companies could register and Hydro One procurement could direct the Hydro One staff to use that. This area was a good opportunity.

Mr. Berardi continued stating that the bid system was an online registration and admittedly it was somewhat cumbersome. It was suggested that it needed to be clearer or more support was needed to be able to navigate it.

[redacted] asked how many First Nation and Métis businesses were registered with Hydro One procurement. Mr. Berardi stated there are about 180 to 200 business registered that were First Nation or Metis. He looked forward to looking at ways to increase this number and raise the profile of their system. Ms. Thistle pointed out that they did not have to be an Aboriginal business to register; they could be a First Nation or Métis individual who could provide a service.

CLOSING REMARKS

Ferio Pugliese thanked all participants for their feedback and the candid conversation. He emphasized that that was what this day was designed for and expressed the intention to get out to Métis communities, as Hydro One recognized the regional diversity that existed. He also stated that Hydro One would take MNO up on the offer in regards to the training program. He also encouraged all participants to contact Hydro One if there were any questions resulting from this session. He also stated that they recognized that electricity in Ontario was a complex environment and they were open to working with the MNO and Métis citizens to support them with information and advocacy.

[redacted] stated that, on behalf of MNO, expressed appreciation to all the Métis community representatives for their participation and also thanked Hydro One for providing this information. She stated that this was a relationship building exercise and was not a consultation. She also indicated that participants will be receiving meetings notes and photos from this meeting.

Senator [redacted] closed the meeting with a prayer.

Indigenous Relations – Executive Summary

January 2018

Chief of Ontario Provincial Engagement Session

Hydro One will host its second First Nations Engagement Session on February 21, 2018 at Casino Rama. The purpose of the engagement session is to strengthen our relationships with the 88 First Nation communities we serve, listen to key energy transmission and distribution related issues and concerns they may have and together find solutions moving forward.

Hydro One had a very open and constructive dialog last year that allowed us to learn from each other and at that time we reaffirmed our commitment to continue advancing our relationship with First Nation communities. Many Chiefs expressed frustration at the pace of activity when dealing with Hydro One in the past. We assured them that Hydro One's management team places an enormous importance on First Nations and told them they can expect to see swift action going forward. Appendix A attached hereto highlights the issues raised at last year's engagement session along with the progress made by Hydro One on these matters.

This year the engagement session will focus on: Customer Service; Procurement & Business Partnerships; Employment and Training; and Transmission and Distribution Planning & Reliability Performance.

Treaty #3 Regional Engagement Sessions

Hydro One hosted three engagement sessions on Treaty #3 Territory in Q4 of 2017. Host communities included Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation, and Couchiching First Nation. Of the 25 First Nation communities located in Treaty #3, Indigenous Relations staff met with 15 communities.

The Hydro One team reinforced working relationships between Treaty #3 First Nation communities and Hydro One; shared information on Hydro One's initiatives benefiting First Nation communities; and discussed challenges and opportunities in moving forward. Hydro One provided additional information on procurement and customer service, including the new First Nations Delivery Credit and employment and training. Common issues and concerns related to: three phase power to support infrastructure development, growth of the communities, and consideration for the new First Nations Delivery Credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

A long term strategy needs to be considered on matters related to power quality/reliability in these communities, and their interest in converting from single phase to three phase power to support community energy plans and infrastructure development.

November 2017

Engagement Sessions

Hydro One has hosted and participated in several engagement sessions throughout the year. A summary of issues rose at these engagement sessions, along with results and progress achieved to-date, is provided below.

Top Five Issues February to September 2017 [1]		Results and Progress Achieved
 Affordability	• Communities feel disproportionately impacted by high electricity costs and that delivery charges are higher than consumption both at the individual costumer level and band level.	• Implemented Ontario Fair Hydro Plan reducing bills by as much as 40 to 50%. • Implemented Get Local Initiative reducing arrears. • Implemented First Nations Conservation program reducing energy consumptions and indirectly bills. • Preparing to roll-out the Affordability Fund.
 Reliability	• Communities are impacted by several lengthy power outages, resulting in insufficient electricity supply to serve businesses. • Existing power loads becoming an impediment to implementing community growth plans.	• Increased capital investments replacing aging assets and reducing outages. • Leveraged technology (Distance-to-Fault) to monitor unplanned outages. • Reduced planned outages by bundling renewal work where applicable. • Targeted tree trimming.
 Liability and Access	• Outdated access rights/permits with insufficient compensation, or the lack thereof, for transmission and distribution assets on and off reserve land. • Improper notification protocols for planned and non-planned disconnection related work.	• Progressed with negotiations to settle outstanding real estate agreements. • Initiated discussions to develop an Indigenous Integration Plan with Real Estate which will include strategies and plans to seek certainty on access rights. • Initiated discussions to develop an Indigenous Integration Plan with Provincial Lines and Forestry which will include communication

[1] Chiefs of Ontario First Nations Feb. 9 & 10; Métis Nation of Ontario May 13; Grand Council of Treaty 3 Fort Frances May 18; Anishinabek Nation August 17; Treaty 3 Wabigoon Lake Ojibway Nation September 12.

		protocols.
Partnership	• First Nation communities seek an increase in procurement, investment, ownership opportunities, and other business partnerships.	• Increased procurement opportunities. • Developed set-aside strategy for an RFP. • Progressed with negotiations to reach equity partnership agreement on Tx project (Niagara Reinforcement Project)
Employment	• First Nation communities are interested in more employment opportunities and training.	• Increased employment with new permanent hires. • Participated in career fairs and workshops promoting employment and training.

Chippewas of Rama First Nation

Hydro One held an information session at the Chippewas of Rama First Nation for the Anishinabek Nation on Agust 17, 2017. The goal and objectives were to: reinforce working relationships between Anishinabek Nation First Nation communities and Hydro One; share information on Hydro One’s initiatives benefiting First Nation communities; and to discuss challenges and opportunities in moving forward. 30 Anishinabek Nation representatives attended the session.

Treaty #3 Regional Engagement Sessions

Hydro One participated in a Treaty #3 Regional Engagement Session on September 12, 2017 in Wabigoon Lake Ojibway Nation which was attended by members of Wabigoon Lake Ojibway Nation and Eagle Lake First Nation Chief and Council. Additional Dryden region communities invitees included: Lac des Mille Lacs First Nation, Lac Seul First Nation and Wabauskang First Nation. In total 7 First Nation representatives attended the session.

The goal and objectives were to: reinforce working relationships between Treaty #3 First Nation communities and Hydro One; share information on Hydro One’s initiatives benefiting First Nation communities; and discuss challenges and opportunities in moving forward. Hydro One presented information on Indigenous Procurement, Customer Service including the new Delivery Charge Credit and Employment and Training. Common issues and concerns related to: 3 phase power to support infrastructure development and growth of the communities, and consideration for the new delivery charge credit to apply to on reserve commercial accounts (i.e., band offices, schools, arenas, etc.) where high costs remain a burden.

It was agreed that Hydro One's Indigenous Relations team would follow up on all action items in a timely manner. Plans are moving forward to host two more engagement session in the Treaty #3 territory with First Nations in the Kenora and Fort Frances areas. The next session will be in Kenora on November 22 and 23 and the host community is Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles) First Nation – 11 First Nation communities have been invited. The second session will be in Fort Frances on November 29 and 30 and the host community is Couchiching First Nation – 8 First Nations communities have been invited.

Chiefs of Ontario First Nations

As a follow-up to a commitment made at the February 9 and 10, 2017 engagement session, Hydro One is planning a second annual gathering with the Chiefs of Ontario First Nations on February 21, 2018 at Casino Rama. The purpose of this gathering is to share progress made on most common issues raised at the February 2017 session and to discuss plans to resolve outstanding common issues. The most common issues raised at the February 2017 session were: community visits and outreach; outstanding real estate agreements; customer service programs; increasing Indigenous employment, procurement, partnerships; disconnections; establish emergency and community protocols; and address tax exemptions for First Nations customers living off-reserve.

May 2017

On February 9th and 10th, 2017 the HONI's Board Committee Members participated in an engagement session with First Nation Chiefs in Ontario. All First Nation Chiefs from communities served by HONI, 88 in total, and the Ontario First Nations Regional Organizations were invited to attend the engagement session with the HONI's Board Members, President and CEO and numerous Senior Executive.

The purpose and objective of the engagement session were to hear the Chiefs' thoughts and goals to achieve meaningful progress and build a new vision for HONI's and First Nation communities' collective futures. The Métis Nation of Ontario communities was also invited to a similar session which will be held in May 2017. In addition, the engagement session was a great opportunity to share HONI's thinking and solicit feedback on the application for Distribution

Rates and the distribution system plan that HONI's was preparing for submission to the Ontario Energy Board.

HONI held an engagement session in February 2017 with the First Nation of Ontario communities and the Ontario First Nations Regional Organizations. The purpose of the engagement sessions was to discuss with First Nation communities HONI's distribution rate filling with the OEB. The OEB rate filling document covers the following elements:

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

Where issues do fall within HONI's authority, jurisdiction, and mandate and there are no existing responsive initiatives, HONI will work in collaboration with affected communities to explore, define, and prioritize additional strategies and processes to effectively address these concerns.

Where there are existing initiatives, HONI will continue to work to make meaningful progress in addressing these concerns and consider new initiatives that may assist HONI in this effort. The development of such strategies and processes with First Nations and Métis communities will proceed on the basis of the following principles: action oriented, collaborative, transparent, cost effective and efficient.

Appendix A

Follow-Ups to Chiefs of Ontario First Nations' February 9 & 10, 2017 Engagement Session

	STATEMENT	COMMITMENT	FOLLOW-UP
1.	Mr. Schmidt lists three (3) things he is hopeful will come out of this session: 1. To listen and learn; 2. Provide some education on who is responsible for what, what we each do, how can we as a company can to advocate for you and your community; and, 3. Commit to action. The hope is to move this conversation to an outcome (educate/advocate/action).	Committed to action.	See below
2.	Mr. Schmidt suggests that the feedback that they get from the engagement sessions will go into their upcoming distribution rates submission to the OEB. The information will be collected as part of the application and the First Nations participants' voices will be heard there.	Committed to include FNs feedback into OEB submission.	Included FNs feed-back see Hydro One Networks' Distribution Rate Application (EB-2017-0049) to the OEB Exhibit A Tab 4 Schedule 2 - First Nations and Métis Strategy
3.	Hydro One has met with many First Nations over the last 8 years, including over 200 community visits. Mr. Schmidt suggested that communities interested in inviting Hydro One to visit, attendees should introduce themselves to Ms. Cameron and she will get a team out there.	Committed to community visits when invited.	Completed over 10 new community relationship building visits/outreach since February 2017.
4.	Hydro One is committed to making a change as demonstrated by offering additional regional outreach on procurement, by participating in First Nations employment, training and career fairs and through the First Nations Conservation Program.	Committed to change through additional outreach.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
5.	Mr. Schmidt noted that it is important for Hydro One to hear from the participants and focus on things that can be changed. He committed to listen, but also committed to meeting again in the future to work on some of the things we want to accomplish together. It will take bold action by all of us to effect change.	Committed to meet again.	Completed the following regional engagement sessions: Grand Council of Treaty 3 May 2017; Anishinabek Nation August 2017 and Fall/Winter 2017 hosted three engagement sessions in Treaty #3 Territory - Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles First Nation), and Couchiching First Nation.
6.	Mr. Schmidt shared that he cannot speak to what has happened in the past, but going forward, the focus is on getting people connected rather than disconnected. He also committed to dealing with the issue of cut-offs himself, along with Hydro One legal counsel. The time frames will be addressed, but in general there is no gain for anyone by cutting people off. The larger issue is that we need the cost of power to be reasonable.	Committed to deal with issue of cut-offs.	Extended the Winter Relief Program until June 2017. Reinforced our service level commitment for new connections within five business days with a $75 guarantee.
7.	Mr. Schmidt stated that he agreed with Councillor White, that Hydro One needed to be reasonable and to rethink previous behaviours that were practiced. He notes that there are a lot of attitudes to change	Committed to rethink behaviours and change attitude throughout the	Implemented an internal Leadership Learning Program on Indigenous Relations (On Line & In Class) with over

	throughout the organization and hopes to do better.	organizations.	125 leaders. Conducted 5 Indigenous Cultural Awareness Employees Workshops (Who's Who in the Electricity Sector & Supply Chain).
8.	Chief Patricia Faries said there are power lines going through her land that are intrusive. She expected a response on how her community would be engaged and compensated. Mr. Schmidt introduced Jamie Scarlett and Gary Schneider who can sit and meet with communities to work through their issues. Jamie Scarlett, Hydro One, provided his email address (Jscarlett@hydroone.com) in order to set up future conversations.	Committed to meet with communities to work through real estate issues.	Hydro One Real Estate sent an email to Chief Fairies on September 27, 2017 with no reply yet. Also Hydro One delivered to the Moose Cree First Nation community its Home Assistance Program in August 2017 including support for internal community liaison capacity.
9.	On the question of how do we keep the costs down, Hydro One intends to have a customer presence in local offices; the customer bill was redesigned because customers need to understand the bills; Hydro One has reinforced the commitment to service and of responding in a timely manner.	Committed to reinforce customer service and to respond in a timely manner.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
10	Mr. Schneider shared that he works on procurement as well as land matters. When it comes to the issue of land he has heard the frustration in the room and agrees that agreements with First Nations need to move forward.	Committed to move forward on real estate agreements.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
11	Mr. Lister introduced himself as a new member of the Hydro One team and shared his commitment to changing the way they do business. He stated that he intended to listen and welcomed the opportunity to dialogue.	Committed to changing customer service.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
12	Mr. Pugliese said they committed to visiting First Nations communities, reconnect those who are disconnected, and waive the fees. He asked that the participants let them know which of their community members need this assistance.	Committed to visit communities, reconnect those who are disconnected, and waive the fees.	Followed up with a number of communities e.g., Cat Lake, Pic Mobert and Six Nations
13	Mr. Lister indicated that they had solutions and ideas to give to the Minister. Many of the short-term solutions that are needed in the communities can be acted on immediately. Hydro One is willing to visit communities that they have not yet visited. For people having difficulty with payments, there can be new payment plans set up.	Committed to visit communities to set up new payment plans.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions.
14	Mr. Pugliese noted that Hydro One has launched "Get Local" and written letters to all customers. They are in the process of re-establishing regional or community business offices. They are currently building plans to reinstate regional/community offices to resolve customer issues. In addition, Hydro One is putting a great deal more emphasis on Indigenous Affairs and building more of a strategy around that builds on the good work of Mr. Cameron. This engagement session is the beginning of how Hydro One wants to move forward in doing business. They want to go to the community and regional level on a regular basis.	Committed to meet at community and regional levels on a regular basis.	Completed the following regional engagement sessions: Grand Council of Treaty 3 May 2017; Anishinabek Nation August 2017 and Fall/Winter 2017 hosted three engagement sessions in Treaty #3 Territory - Wabigoon Lake Ojibway Nation, Ochiichagwe'Babigo'Ining Ojibway Nation (Dalles First Nation), and Couchiching First Nation.

15	In response, Mr. Hubert notes that forums such as this are intended to drive change. He also committed to finding out about the Ontario Energy Board process when it comes to the discussions that the OEB held on the First Nations Rate.	Committed to find out what were OEB discussions held on the FNs rate.	See Report to the Minister Options for an Appropriate Rate Assistance Program for On-Reserve First Nations Electricity Consumers December 29, 2016.
16	Mr. Hubert explained that there is a delivery charge in both, but the majority of the delivery charge is for distribution. Mr. Hubert referred to his PowerPoint [Slide 6] and noted that electricity makes up the majority of the charge. He also committed to provide both hard and electronic copies of the presentation to the attendees.	Committed to provide both hard and electronic copies of Mr. Hubert's presentation.	Presentations and session reports provided to all participants – see https://www.hydroone.com/about/indigenous-relations/first-nations-engagement-sessions
17	Chief Brian Perrault recounts an incident last spring where there was a Hydro One crew in his community clearing trees around the lines. The crew came right into his yard where he had 5 trees. Instead of trimming the trees, they cut them all down. The Chief's wife's grandfather planted those trees and he felt like he should have been spoken to about it before they were cut. Mr. Penstone said that Hydro One has not trimmed in a long time. There are OEB standards related to dying and diseased trees. However, Mr. Penstone felt that he could not comment any further because he did not know about the specific situation. In addition, he committed to following up.	Committed to follow-up on Chief Perrault's tree cutting issue.	Couchiching First Nation Chief Perrault talked to Ferio when he was up in the area in May and Ferio asked the Chief to send the pictures to him. In late July Chief said he still hadn't sent the pictures to Ferio. IRD followed up in late Fall and met with Chief Perrault at his house to take the photos. Internal follow-ups undertaken.
18	Mr. Kiraly mentioned that related to emergency planning, there are some relationships with communities around that, but he recognized that there is certainly not enough of that going on. He continued that they are open to any protocol that the Chiefs feel is most appropriate, for example, Hydro One workers stopping at the band office to let the leadership know what is going on. Mr. Kiraly concluded by saying that many of the items that Chief White-Eye mentioned were possible to achieve.	Commit to discuss emergency planning including protocol with communities.	Engaged with Provincial Lines and Forestry to develop an Indigenous Relations Integration Plan which will include communication protocols with FN communities.
19	Mr. Pugliese on Longer term issues: There is a need to address longer term issues including outstanding agreements around access, rights, land use, assets on the land. There have been fruitful agreements in the past and Hydro One will continue to work on agreements with First Nations.	Commit to address outstanding real estate agreements.	Continued discussion and negotiations on the 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
20	Mr. Scarlett noted that the executive team members see working with First Nations as an overlapping mandate across their areas of focus. He noted that they understand it is critical to deal with costs and rates and Hydro One needs help from the government on that. Senior management understands how acute the issue is for First Nations. Regarding land use and resources, the team learned about how long negotiations have gone on and how this has been unacceptable for First Nations. They do not want these kinds of delays to continue. In order to achieve this, he encouraged direct, open and energized conversations. He encouraged a principled and fact-based method of moving forward. Thirdly, he noted the need to move forward on partnerships and co-ventures and working with First Nations more in the area of procurement.	Committed to open up discussions on real estate agreements and move forward on partnerships, co-ventures and procurement.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements. Signed MOUs with 2 First Nations which contemplates equity ownership on a Tx line. Increased Indigenous Procurement with total spends of $24.06M (surpassed 2017 target of $19.8M by 27%). Delivered 5 Indigenous Interactive Procurement Workshops with both Indigenous and non-Indigenous

			businesses.
21	Mr. Pugliese noted that he wants to be back here celebrating success in one year. The comments will be shared with board members. He concluded by noting that the meeting will end but the conversation will not. He encouraged participants to reach out to Hydro One if there is something you would like to add, and Hydro One will be happy to come to your communities for similar meeting. Thank you.	Committed to meet in one year and to community visits when invited.	Letter sent on October 30 inviting Ontario Chiefs to the second annual gathering on February 21, 2018 in Rama. Completed over 10 new community relationship building visits/outreach since February 2017.
22	He admitted that the new team at Hydro One recognizes that things had happened in the past when it came to First Nations land and communities. While they cannot change what happened in the past, the new Hydro One team is making a commitment to work differently, in partnership with First Nations. He asked the attendees to judge the new team on their actions. He noted that in a year from now, or sooner, Hydro One will be able to share insights and progress on closing out past grievances, in helping community members with bills, and making movement on affordability.	Committed to work in partnerships with communities and to share progress on closing out past grievances, helping customers with bills and making movement on affordability.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements. Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions. Implemented First Nations Delivery Credit under Fair Hydro Plan.
23	Related to improving Hydro One's responsiveness, Mr. Pugliese noted that they have heard First Nations speak about empty promises from the past. The new team at Hydro One will improve on this performance.	Committed to improve performance on following up on commitments made.	See all follow-ups above and below and letter sent on October 30, 2017 inviting Ontario Chiefs to the second annual gathering on February 21, 2018.
24	Mr. Pugliese asked participants to let Hydro One know what they wanted in terms of training programs for communities. They are willing to go to communities to work on individual bills, explain the bills, and get clients on plans; however, these activities take many visits. Another option is training people within communities to host these meetings and provide this service within the community. These programs are just getting started, but Hydro One will continue to work with communities in this area.	Committed to visit communities to work on bills and plans and offered community training to support customer services.	Implemented Get Local Initiative reducing arrears by visiting 19 communities and holding 1282 one-on-one sessions and offered community liaison capacity to 6 First Nations.
25	Chief R. Donald Maracle noted that some councils loan monies to community members for bills in arrears. He asked what Hydro One could do for communities in this situation. Some people have had to go to high interest rate companies to borrow, which is a hard cycle for people to get out of. Mr. Pugliese responded that people would generally have to rely on social service agencies and that Hydro One does not have a policy on this issue, but can potentially look into it. In addition, he noted that they spoke with the Premier on affordability funding. The current program qualifiers are stringent but perhaps Hydro One can use the surpluses in cases such as this. The Chief noted that in smaller communities there are no service agencies and have to depend on the band council. Mr. Martinez noted that when they come to the community in March they will bring the United Way with them. Community members can apply for relief from the United Way. He has done this with First Nations communities before. Mr. Pugliese noted that this issue has come up before and is something that they want to look at. They are looking to support an adjudication process in order to address it. This is a potential suggestion for action going forward.	Committed to consider alternate affordability support program.	Currently implementing the new Affordability Fund which can help improve home's energy efficiency with free energy-saving upgrades, which can lower home energy use and electricity bill. Also advocating on delivery credit for First Nations owned buildings.
26	Mr. Pugliese commented that Hydro One cannot address poverty in a general sense. It is a very broad,	Committed to address poverty and	Implemented Get Local Initiative reducing arrears by

	complex social issue. However, Hydro One can focus on the bills as part of their own social responsibility. Also related to community social services, perhaps Hydro One can support those through Hydro One's community giving program.	social issues through bills and sponsorship and grant programs.	visiting 19 communities and holding 1282 one-on-one sessions and approved over $3.5M in Indigenous sponsorships over last 10 years. In 2017 alone reviewed and approved a total of $745,750 in grant/sponsorship proposals supporting healthy Indigenous communities.
27	Mr. Pugliese responded that Hydro One supports Councillor Archibald's position on the delivery charge; however, it is not Hydro One that controls that. Regarding Hydro One staff entering the community, Hydro One has heard this concern previously and believes that their staff must respect the community protocols. They should first visit the band office. Finally, with respect to the disconnection and whether there could be load limiters, Mr. Pugliese noted that there are resources on this that Hydro One is willing to share through their outreach activities.	Committed to respect community protocols when entering communities and to offer load limiters to address disconnections.	Engaged with Provincial Lines and Forestry to develop an Indigenous Relations Integration Plan which will include communication protocols with FN communities.
28	Mr. Pugliese responded that he is sure there must be information on the revenues generated through those agreements. He noted that he and the Chief Legal Officer had been going through all of the agreements to identify what had gone wrong in the past and where there are fixable issues. Hydro One wants to re-evaluate all of those agreements and resolve outstand issues. Regarding submersibles, Mr. Pugliese noted that they are happy to sit and meet to have a discussion. In addition, the Chief Operations Officer would be presenting later and would be better suited for that discussion.	Committed to address outstanding real estate agreements and to discuss submersible lines.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
29	Mr. Schmidt shared that Hydro One met with the majority of the First Nations communities that they serve, which included over 200 community visits. He noted that they are looking to expand community visits and welcomed the participants to let Hydro One know if they were interested in a community visit. He appreciated the goals and aspirations, as well as the needs of First Nations rights-holders and landowners, in terms of business development and community relationships.	Committed to expand community visits when invited.	Completed over 10 new community relationship building visits/outreach since February 2017.
30	Chief Sayers asked if Hydro One would be willing to honour the point of sales tax exemption for all Indigenous people in Ontario no matter where they live. This was his formal request. The Chief's second point is on working for mutual benefit; he wondered how working together would look, and what would be the benefits, in general. Mr. Schmidt asked his staff member, Ms. Cameron to make a note on the issue of taxes. He stated that given the complexity of the tax system there would have to do some analysis on that. He committed to going back to Chief Sayers on that topic. Ms. Cameron sought to clarify Chief Sayers' statement; that the tax can be removed for customers on reserve once Hydro One receives a status number, but she believes what Chief Sayers is referring to is eliminating the taxes even for those First Nations who are not living on reserve. Chief Sayers: The Chief clarified that at the time the agreement was made, there was no differentiation between on-reserve or off-reserve. Ms. Cameron said that Hydro One would go back to their tax group to discuss as well as talk to the province. She noted that they had been audited several times by the Canadian Revenue Agency related to tax collection. She also noted	Committed to follow-up on tax exemption for customer residing off reserve.	No follow-up made.

	that, on a personal level, she agreed with Chief Sayers.		
31	Chief McLeod shared that his band council had to issue 220 cheques to Elders to assist them in paying their hydro bills. That is $88,000 in one month. He notes that it is not just the financial burden; they view it as insulting and immoral. The Chief shared that there are two major lines running through his First Nation, and yet leadership has to explain why citizens who are struggling are getting delivery charges. He noted that his community members are outraged, particularly because Hydro One does not pay anything to the community for the lines running through their territory and then Hydro One turns around and charges outrageous rates. They view this as money that is owed to them, and they need a conversation about that. Mr. Schmidt noted that Hydro One staff needed to meet with Chief McLeod on this issue and wondered if the contract lapsed or was ever renewed? He committed to reviewing these agreements. Ms. Cameron suggested that Mr. Gary Schneider, Hydro One, can talk with the Chief on this issue.	Committed to address real estate agreement.	Completed discussion and negotiations on 4 of 8 outstanding real estate agreements. Engaged with Real Estate to develop an Indigenous Relations Integration Plan which will include strategies and plans to settle outstanding agreements.
32	Councillor Archibald noted that when it comes to projects in their area, the First Nations should be contacted for employment. He noted the case of Otter Rapids specifically. They had sent permits for the band council to review, and when the band signed off, the contractor said "oh sorry, no jobs." Councillor Archibald's second point is related to disconnections. He does not believe that Hydro One staffs are aware of the new policies around working with people one-on-one to avoid disconnections because in his community they just cut people off. He noted that he sent a letter to Mr. Schmidt's office and received no response. Mr. Schmidt assured Councillor Archibald that he responds to every note that comes into his office. He asked that he resend a copy and he will respond. In terms of employment, Mr. Schmidt stated that he could not agree more and wants First Nations employees to participate in projects. He committed to putting people in touch with Ms. Judy McKellar, Executive Vice President, Chief Human Resources Officer. In regards to disconnection, Mr. Schmidt asked participants to let Hydro One know of anyone living without power. Hydro One wants to get them connected. If any community has people headed in that direction, Mr. Schmidt asked them to let Hydro One know and they will try and find a way to manage. In addition, if your community would like Hydro One to make a community visit, just ask.	Committed to connect with HR on project employment opportunities to connect customers and to community visits when requested.	Participated in 8 Indigenous employment outreach sessions in 2017 reaching approximately 200 Indigenous student participants.
33	Chief Maracle reminded the room that land was never surrendered to the Crown, yet the Crown gave letters of patent to others for some of his reserve land. Some members of his community live on that land part time. He wondered if their bills could be tax exempt, as their rights are being infringed on. Mr. Schmidt offered to talk to legal counsel on the issue and help investigate the situation. He noted that, if necessary, Hydro One could advocate the community's position with the provincial and federal governments as well. Mr. Penstone suggested that what the Chief was describing was a federal jurisdictional issue. The land was not surrendered. Secondly, the status of First Nations as it relates to tax is also a federal issue that would have to be determined by the Canadian Revenue Agency.	Committed to discuss with legal and governments to address tax exemptions for non-reserve lands.	No follow-up made.
34	Chief Pamajewon began by describing an issue his community had related to a road. The province was	Committed to consider, with the	Initiated internal discussions IRD & Provincial Lines.

	involved, and the First Nations took them to task on that. Cottagers were pushing the province to build a road west of his community. The community knew that those lands were still theirs. All the blasting required to build that road affected the aquifer and wells dried up. The community had to fight INAC on that issue. His community drilled the well and successfully negotiated with the Ministry of Transportation. Now the community has a water station, which requires power to operate. The Chief noted that there are many power outages and as a result, the community had to purchase generators for the well and the facility. There are a number of outstanding expenses related to power failures. Mr. Schmidt commented that Hydro One formed a group specifically to deal with water station outages. On occasion they have supplied the province with generators and fuel in the past. Mr. Schmidt suggested that perhaps Hydro One could support First Nations in this way, with the support of the province and the OEB.	support of the province and OEB, offering generators to communities for water stations during outages.	
35	Chief Paul Eshkakogan would like to see a table developed to move this work around contracts and employment/training forward. As an example of his frustration, the Chief noted that even on the issue of vegetation management, they could not get anyone on the project because of a union issue. He reiterated that they need jobs in his community to pay the bills. The Chief expressed a desire to come to an agreement to continue the dialogue related to unlocking job and contracting opportunities for First Nations. Mr. Penstone agreed with the Chief and noted that there have been instances where First Nations communities provided material and services for projects. Mr. Penstone directed the comment to his colleagues in procurement. A Hydro One representative agreed with the Chief and suggested that they do a workshop with the community and their businesses in order to participate in the Hydro One sourcing events. He also commented that he supported the idea of a table for dialogue and is considering what that would look like from a strategic perspective. He agreed that they needed to start those discussions.	Committed to offer a procurement workshop and to consider a dialogue table on employment/training/procurement.	Procurement workshops offered when requested. No follow-up made on dialogue table. Increased Indigenous Procurement with total spends of $24.06M (surpassed 2017 target of $19.8M by 27%). Delivered 5 Indigenous Interactive Procurement Workshops with both Indigenous and non-Indigenous businesses.

Summary of Commitments

Common Commitment Themes	%
Community Visits & Outreach	25%
Real Estate Agreements	18%
Customer Services	18%
Employment, Procurement, Partnerships	7%
Cut-offs	7%
Emergency & Community Protocols	5%
Tax Exemptions Off Reserve	5%

Feed-Back to OEB	5%
Tree Cutting	2%
Provide Copy of Presentation	2%
Performance on Follow-Ups	2%
Change Internal Behaviour & Attitude	2%
Sponsorships	2%

Hydro One Métis Nation of Ontario Engagement Session- May 13th

Responses to follow-up questions

A participant noted that Hydro One had cut down a number of trees in the North Bay area to avoid interruptions due to weather but they had not cut down the right trees.

For us to be able to follow up internally we need to know (i) the location of the "wrong trees"- and what are the trees that should have been cut down but weren't? Additionally, it may be helpful to know the timeframe (when/how long ago) did this occur. Hydro One Forestry followed up directly with the meeting guests to address this comment

If there is oil spill from a Hydro one transformer on residential property, how do we clean it up?

Hydro One dispatches a crew to investigate all potential spills that are reported by customers/property owners. The responding crew is trained to do initial containment, complete small cleanups and report internally. A 24X7 On-Call Environment Contact is notified and an Emergency Response Contractor and an Environment & Health Technician are mobilized to complete the larger cleanups, excavating impacted areas. All spills are reported internally in our EHSM data base (Internal reporting system) and external reporting is completed as legally required.

Do we notify the home owner regarding the same and provide them with details as to how we cleaned it up?

Yes, the customer/property owner is informed and the clean-up method is often discussed. Depending on the type of material spilt (pre-1985 electrical insulating oil) the property owner is sent a follow up letter with oil analysis and potentially soil confirmation analysis.

Can potential home buyer access information regarding such oil spills that may have occurred at a residential property they are considering buying?

Hydro One does not provide access to this information. We treat these types of queries on a case-by-case basis. Potential purchasers should be asking the seller for this information, the seller should disclose. For this reason, we provide letters & lab analysis reports on potential PCB spills. Purchasers can also go down the road of a Freedom of Information request to the Ministry Of Environment and Climate Change.

What about Species at Risk legislation when it comes to cutting trees down to protect the lines?

Hydro One takes its responsibility with respect to Species at Risk (SAR) very seriously. During the planning of vegetation management on rights-of-way or line maintenance projects, Hydro One works with the Ministry of Natural Resources and Forestry (MNRF) and other stakeholders to identify if there are any SAR in the work location. If a SAR is identified, we will try to avoid any effects on the species. This may be able to be done with the scheduling of work to a time of year when the work will not affect the species, avoiding accessing the area that the species is in or changing vegetation management technique. If it is not possible to avoid the impact, we will develop a plan to minimize or mitigate the effect. The plan will be registered with MNRF as required in Ontario Regulation 242/08 under the Ontario Endangered Species Act (OESA).

On larger projects, we work with MNRF, stakeholders and often hire a consultant to identify SAR or SAR habitat in the vicinity of the project. This information is taken into account during the design of the project. We will apply for any permits required under the OESA. We will also comply with the Federal Species at Risk Act, where it applies. For larger projects, we usually develop a restoration plan for post construction with biodiversity in mind depending on the surrounding land uses. Currently, we are working with OMAFRA, MNRF, the David Suzuki Foundation and other stakeholders on the creation of pollinator habitat on some of the transmission Right of Way and station sites.

We have developed materials to train our staff in the identification of Species at Risk and the processes to follow if they are identified in the work area. We have several biologists that are employed by Hydro One that advise on SAR mitigation and habitat creation.

What are wood poles treated with and could this negatively affect vegetation in the area?

The types of chemical used to treat our wood poles depend on the type of wood. Hydro One uses Copper Chromated Arsenate (CCA) for treating Cedar poles and CCA-PEG

(Polyethylene glycol) for treating Pine poles. Hydro One's poles go through a treatment fixation process which affixes the treatment to the wood and limits any leaching. There may be some minor surface leaching, but this will typically take place while the poles are still in storage, prior to installation. There are no concerns with our treatment negatively affecting vegetation in the area of where the pole is installed.

Does Hydro One have an employment coordinator that could assist them with the process of applying to apprenticeships?

All applications must be submitted online via the www.PWU.ca website. For any issues, the Power Workers Union (PWU) can be reached at: Toll Free: 1-800-958-8798. They can also email Aboriginal.Recruitment@HydroOne.com

What are some of the interview techniques used by Hydro One?

Hydro One uses a number of interview techniques – behavioural questions, scenario based questions, presentations where candidates are asked to develop and deliver a presentation on a particular topic as well as some testing for things like Excel. As part of the interview process we also conduct psychometric assessments where candidates are asked to answer a number of questions on their computer.

How does Hydro One hire for promotions- are efforts focused on internal promotions?

Hydro One must abide by the collective agreement with regards to vacancies or promotions. For all management positions, Hydro One has a robust development and performance plan that all employees are asked to participate in.

Where are Hydro One's training facilities located?

Hydro One has training facilities in Kleinberg and Orangeville.

Nakina DS F2 & Moosonee DS F1/F3 Energy Storage Reliability Overview

June 15, 2018

Assumptions and Context

- HONI has recently explored Non-Wires Alternatives (NWA) to improve reliability to Anwaatin communities.
- Key issues associated with NWA include storage sizing, location, cost, and "islanding" operational concerns.
- This analysis is based on total community load. Variability in load may impact the battery backup duration to the community.
- Targeting critical loads for backup would reduce the battery size required, and hence the total cost.
- Cost estimates are based on informal vendor discussions, and publicly available information plus contingency due to remote access/unknown variables.
- Optimal location of the battery is in close proximity to the community to maximize the reliability benefit.

Feeder Supply to Anwaatin Communities

- Nakina DS F2 – supplies Aroland First Nations
- Moosonee DS F1 & F3 – supplies Mocreebec First Nations

Reliability Ranking of Supply Feeders

Ranking without Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	1988	2146
Moosonee DS F1	498	549
Moosonee DS F3	1134	1184

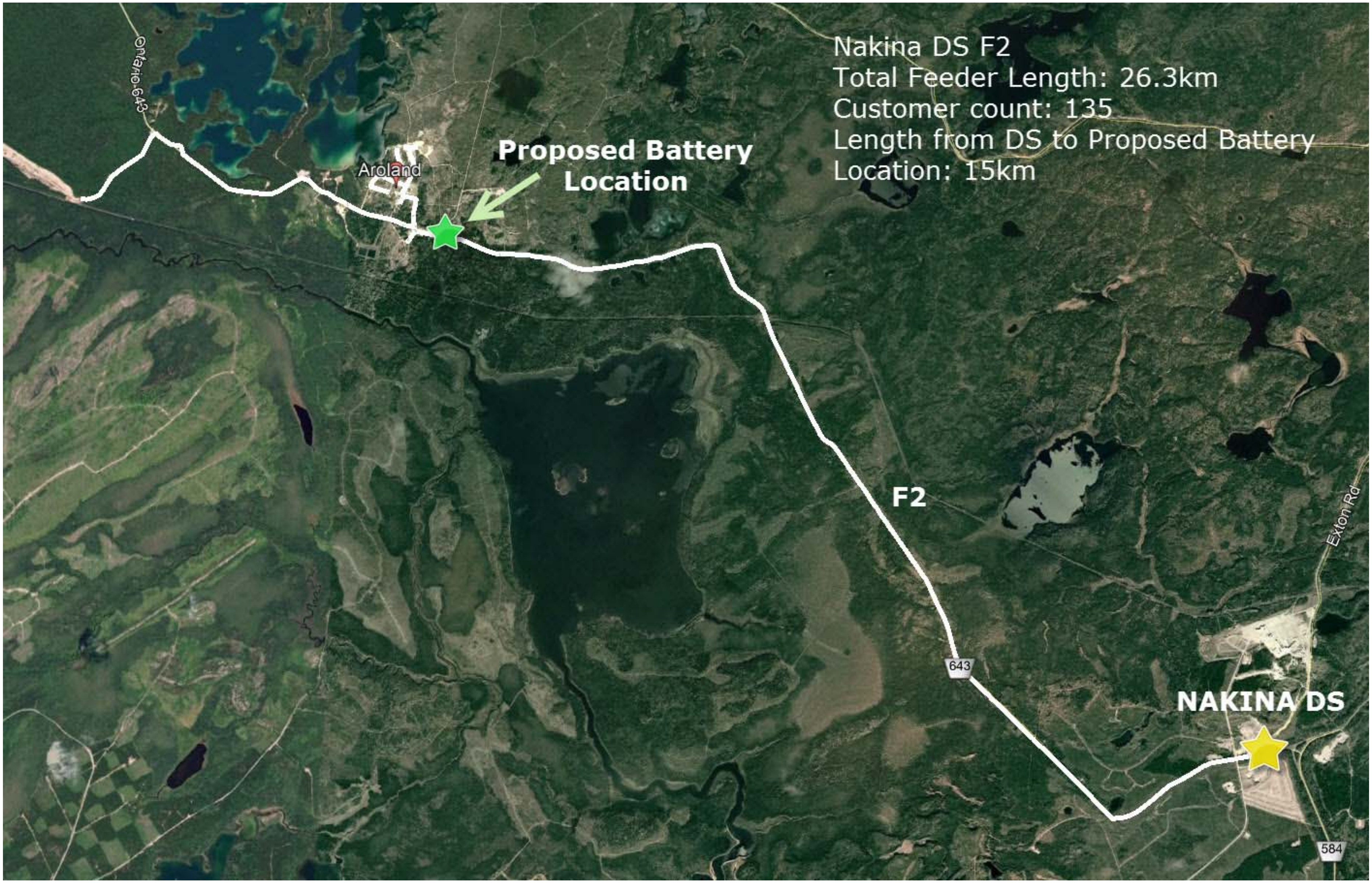
Ranking with Transmission Loss of Supply*

	SAIDI Ranking	SAIFI Ranking
Nakina DS F2	2022	2183
Moosonee DS F1	431	412
Moosonee DS F3	864	678

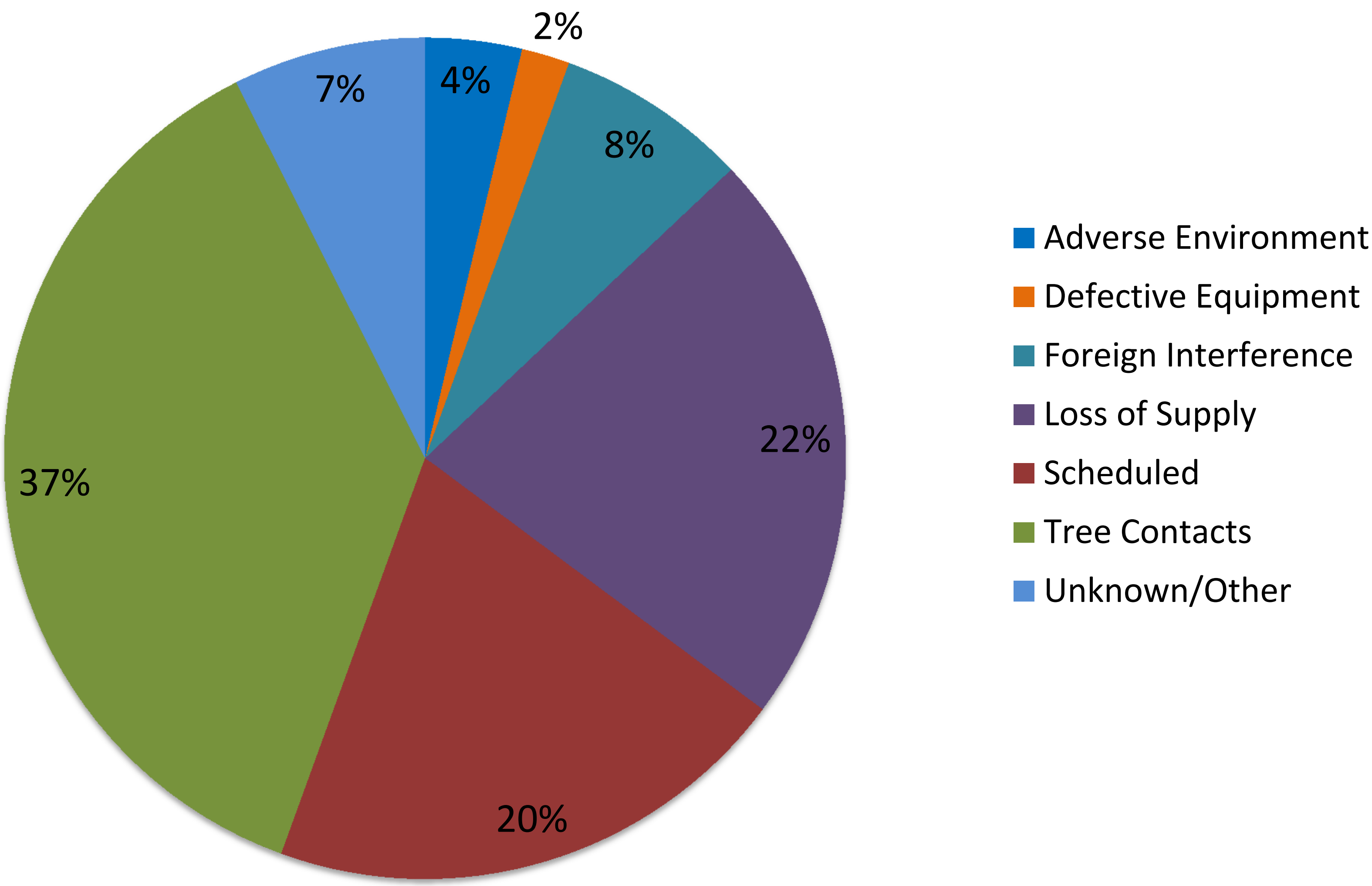
*Ranking based on 2015-2017 average data, out of approximately 3300 feeders. Feeder ranking is from worst to best, with "1" being the worst.

Nakina DS F2
Energy Storage
Reliability Overview

Nakina DS F2

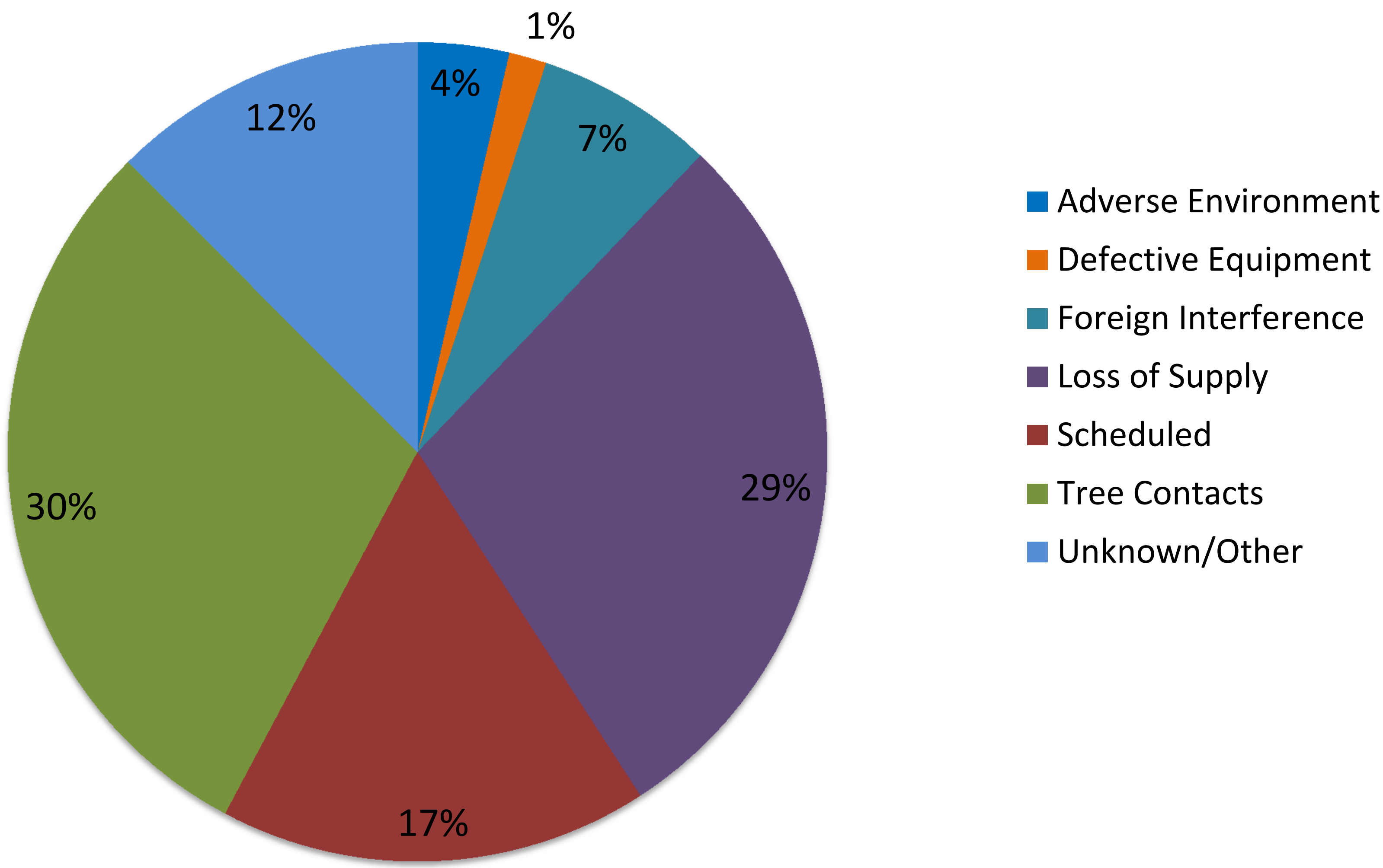

Nakina DS F2
Total Feeder Length: 26.3km
Customer count: 135
Length from DS to Proposed Battery
Location: 15km
Proposed Battery
Location
Aroland
Ontario 643
F2
643
NAKINA DS
Exton Rd
584

Nakina DS F2 - Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.

Nakina DS F2 - Duration of Upstream Outages by Cause (5 Years)

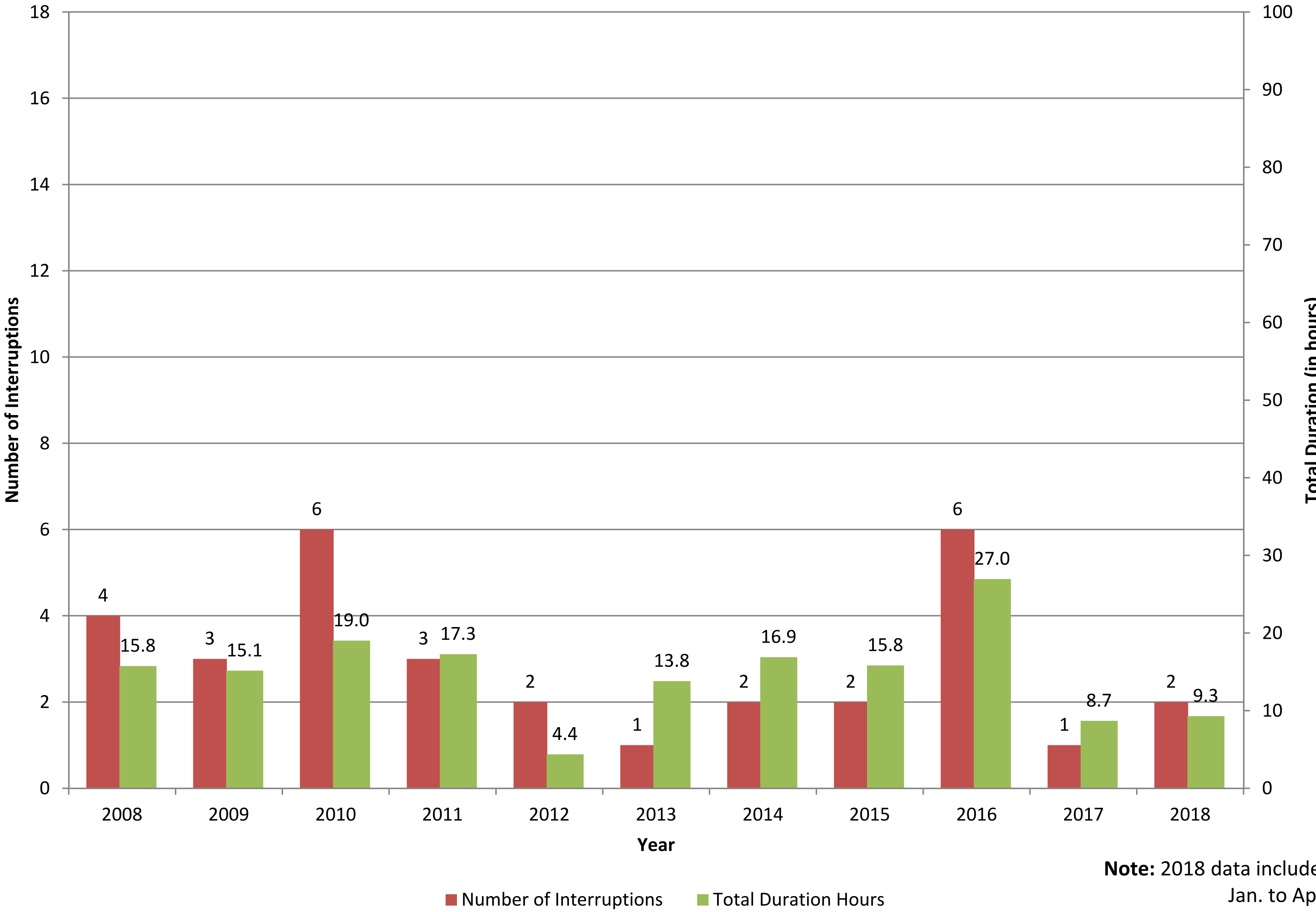


*Vegetation management will improve by 20-40% over the planning period.

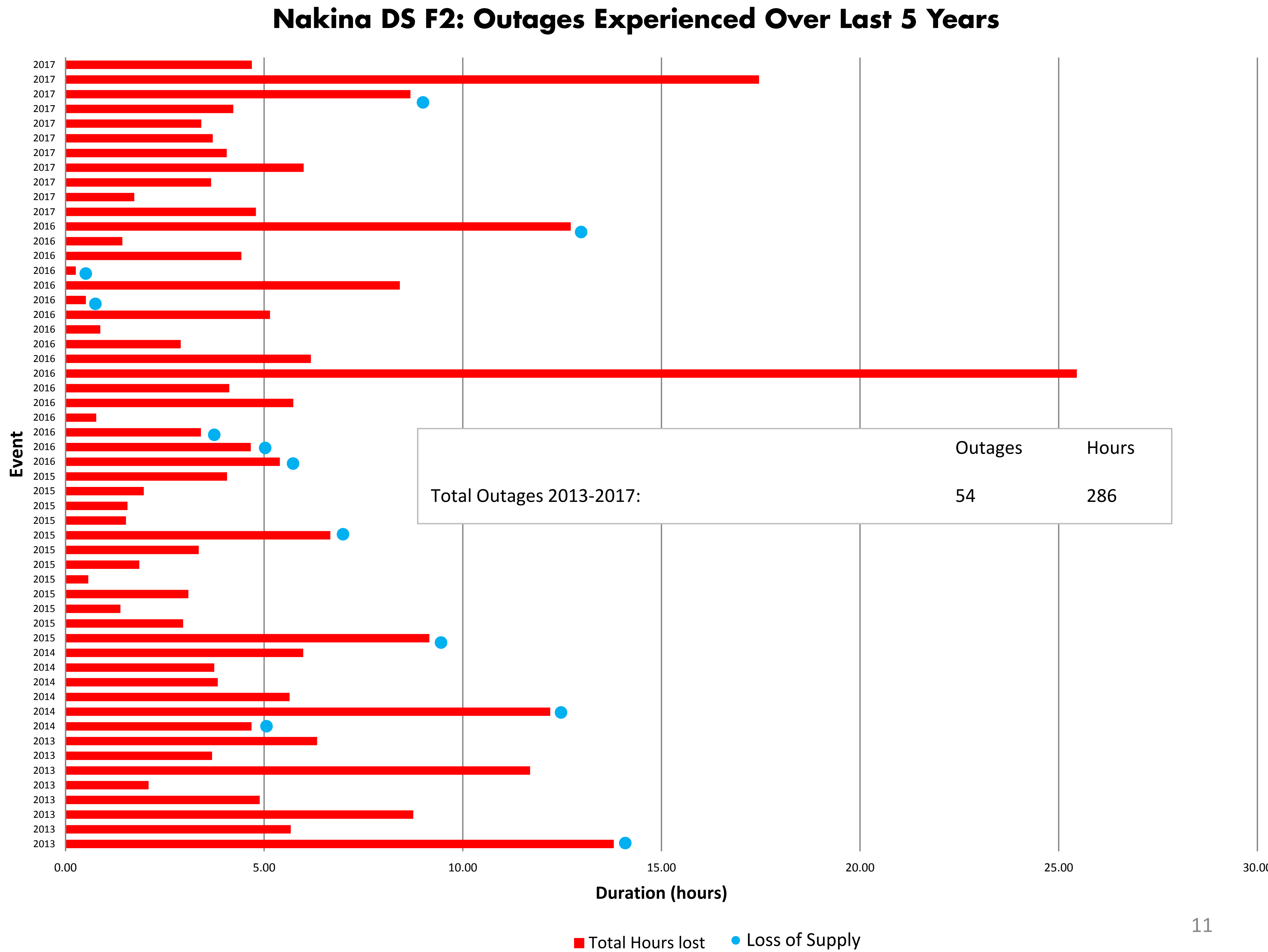
Nakina DS F2 - Number and Total Duration of Outages by Year

Year	Number of Outages	Total Duration of Outages (Hours)
2013	8	57
2014	6	36
2015	12	38
2016	17	92
2017	11	62

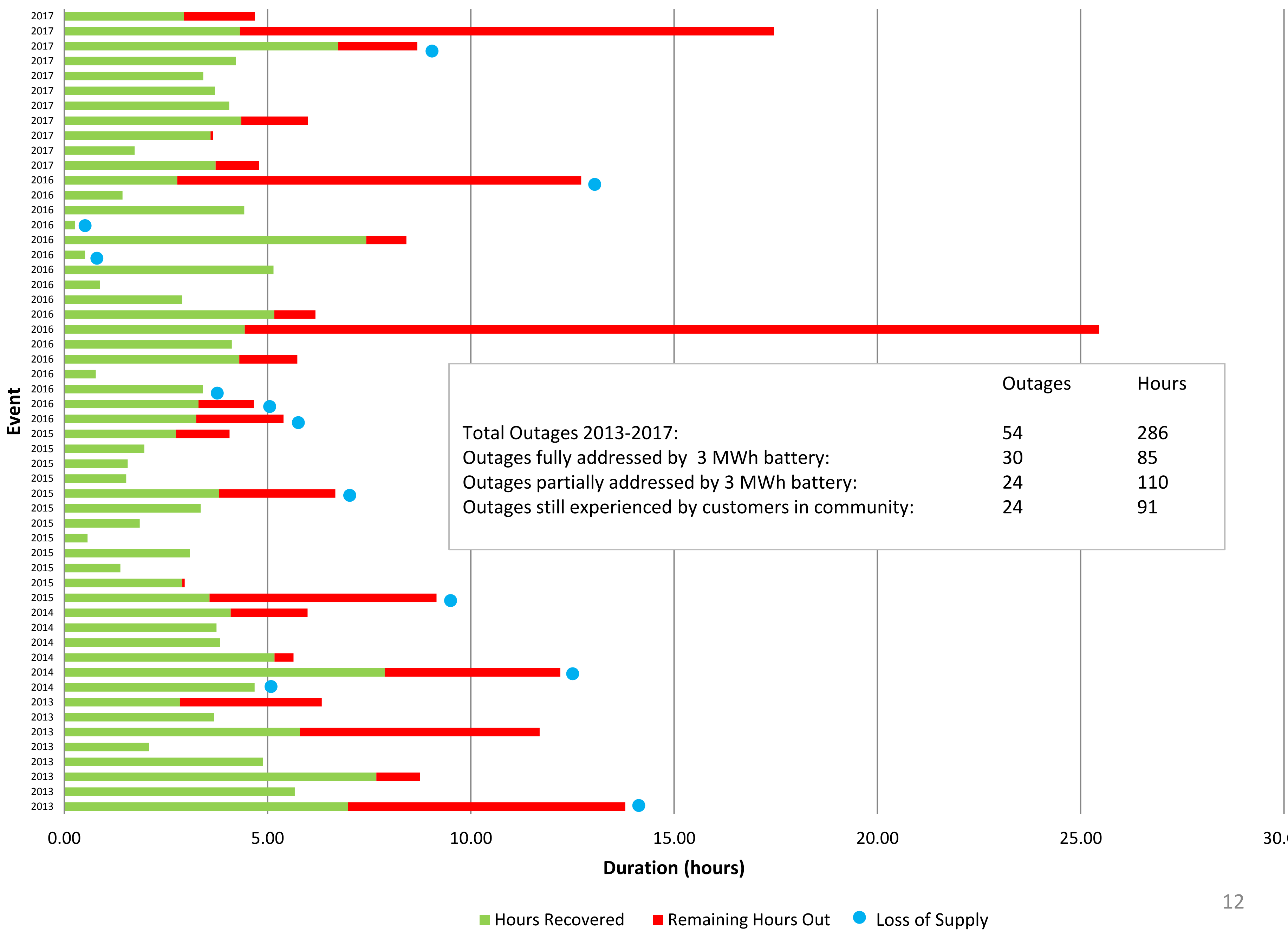
Transmission Loss of Supply Interruptions for Nakina DS over 10 Years



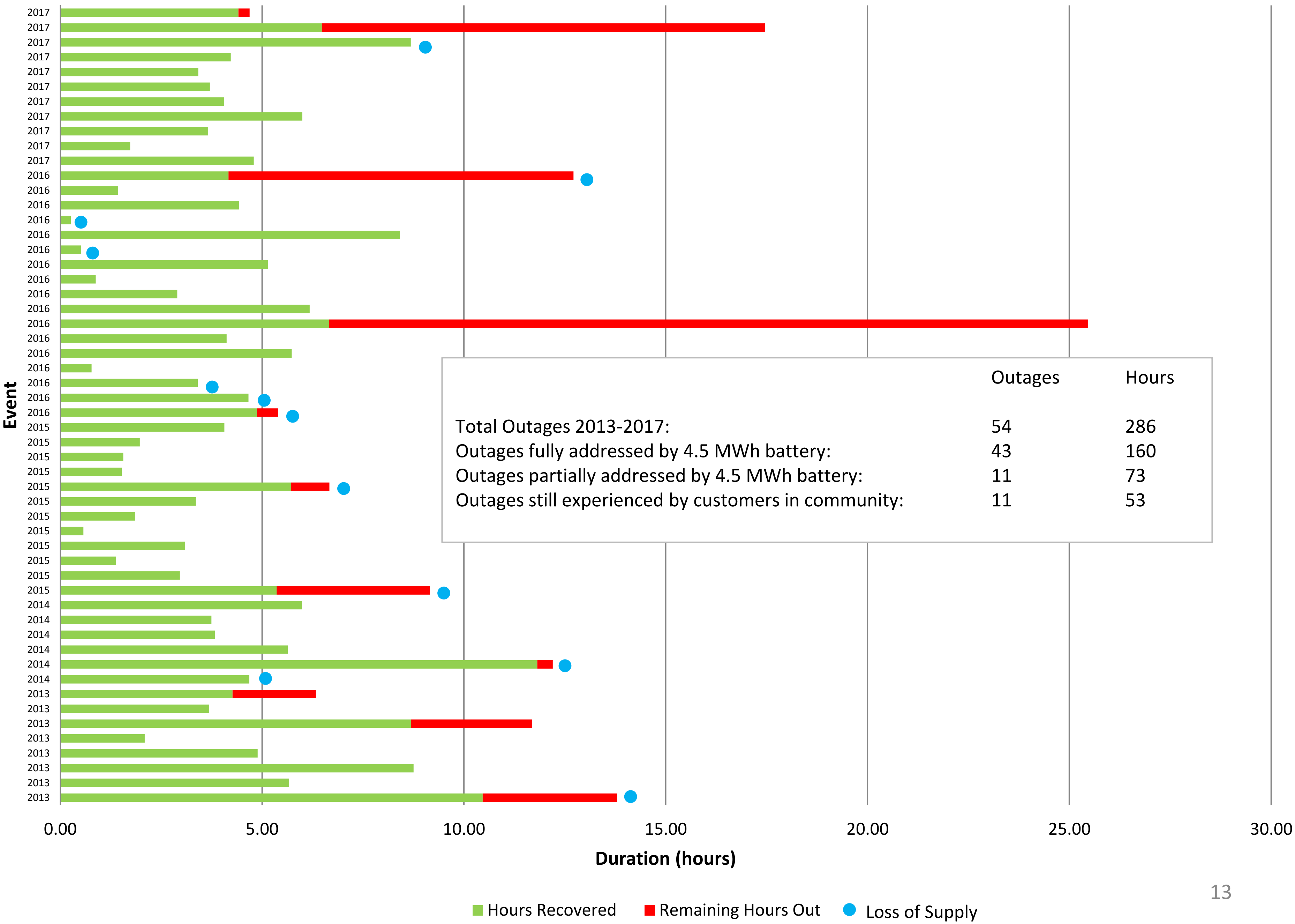
Note: 2018 data includes Jan. to Apr.


Nakina DS F2: Outages Experienced Over Last 5 Years
Event
Duration (hours)
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Outages
Hours
Total Outages 2013-2017:
54
286
Total Hours lost
Loss of Supply
11

Nakina DS F2: Outage Impact with 1.5MW, 3MWh energy storage ($4.5M)

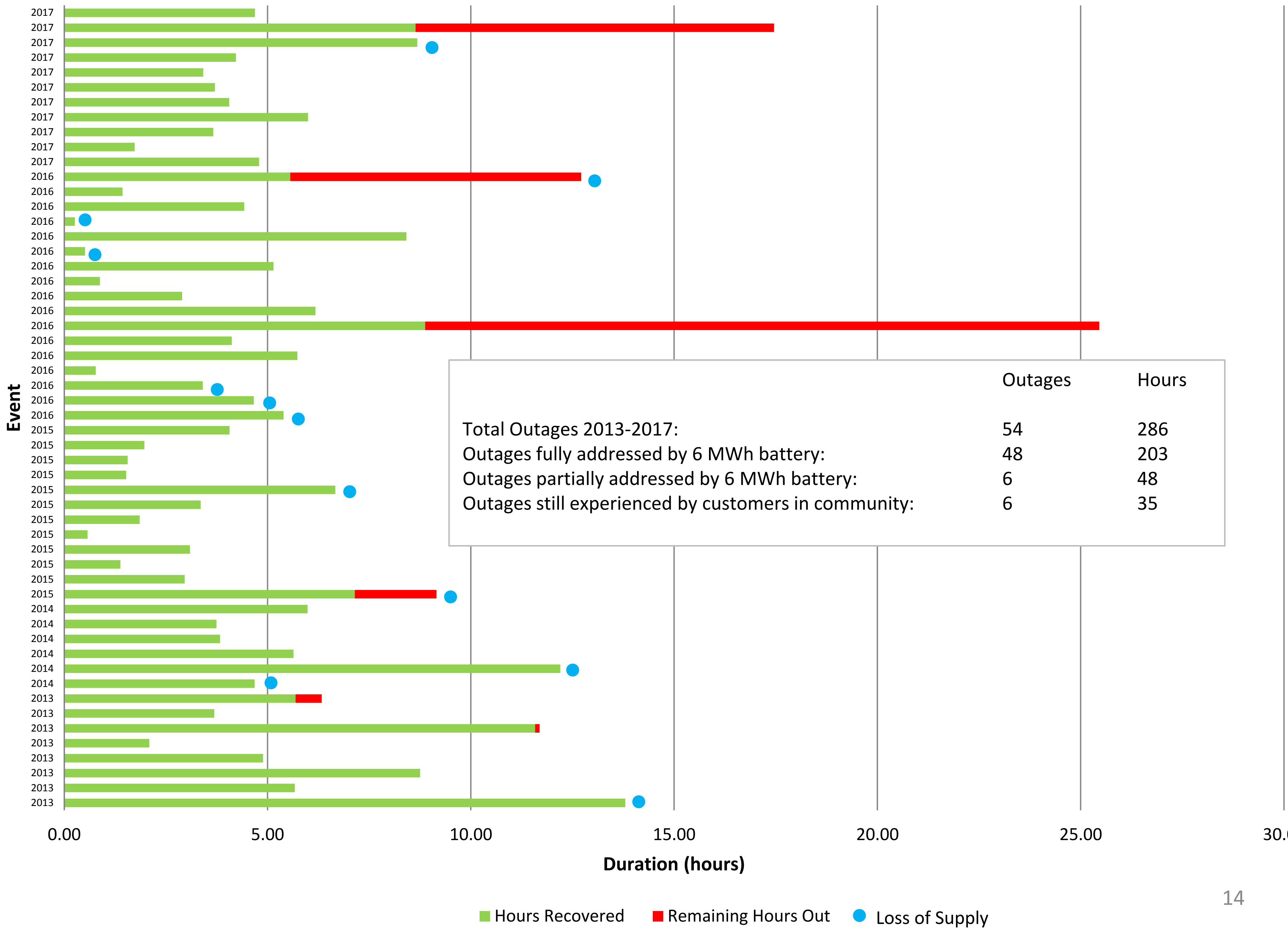


Nakina DS F2: Outage Impact with 1.5MW, 4.5MWh energy storage ($6.8M)



13

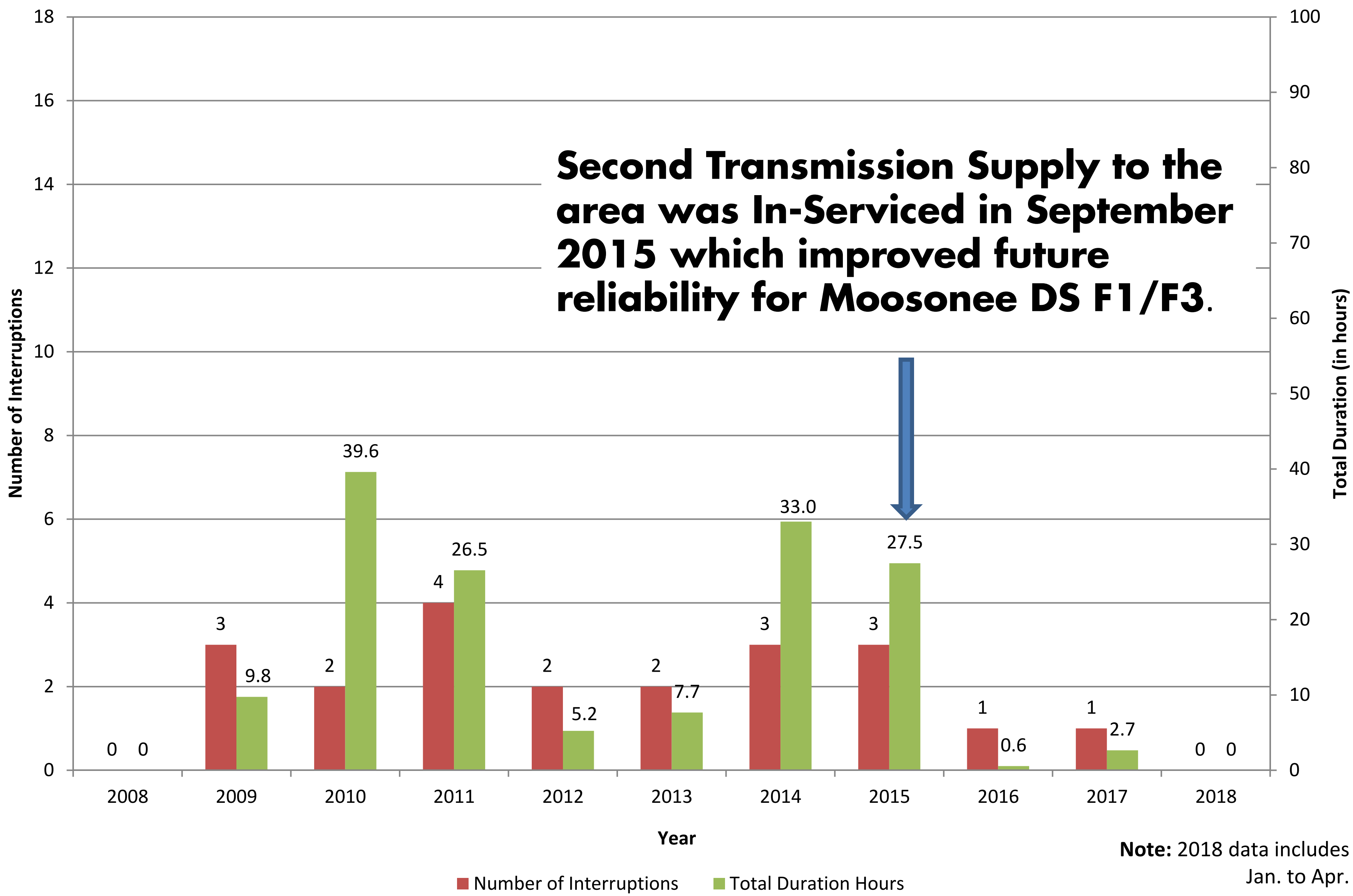
Nakina DS F2: Outage Impact with 1.5MW, 6MWh energy storage ($9M)



14

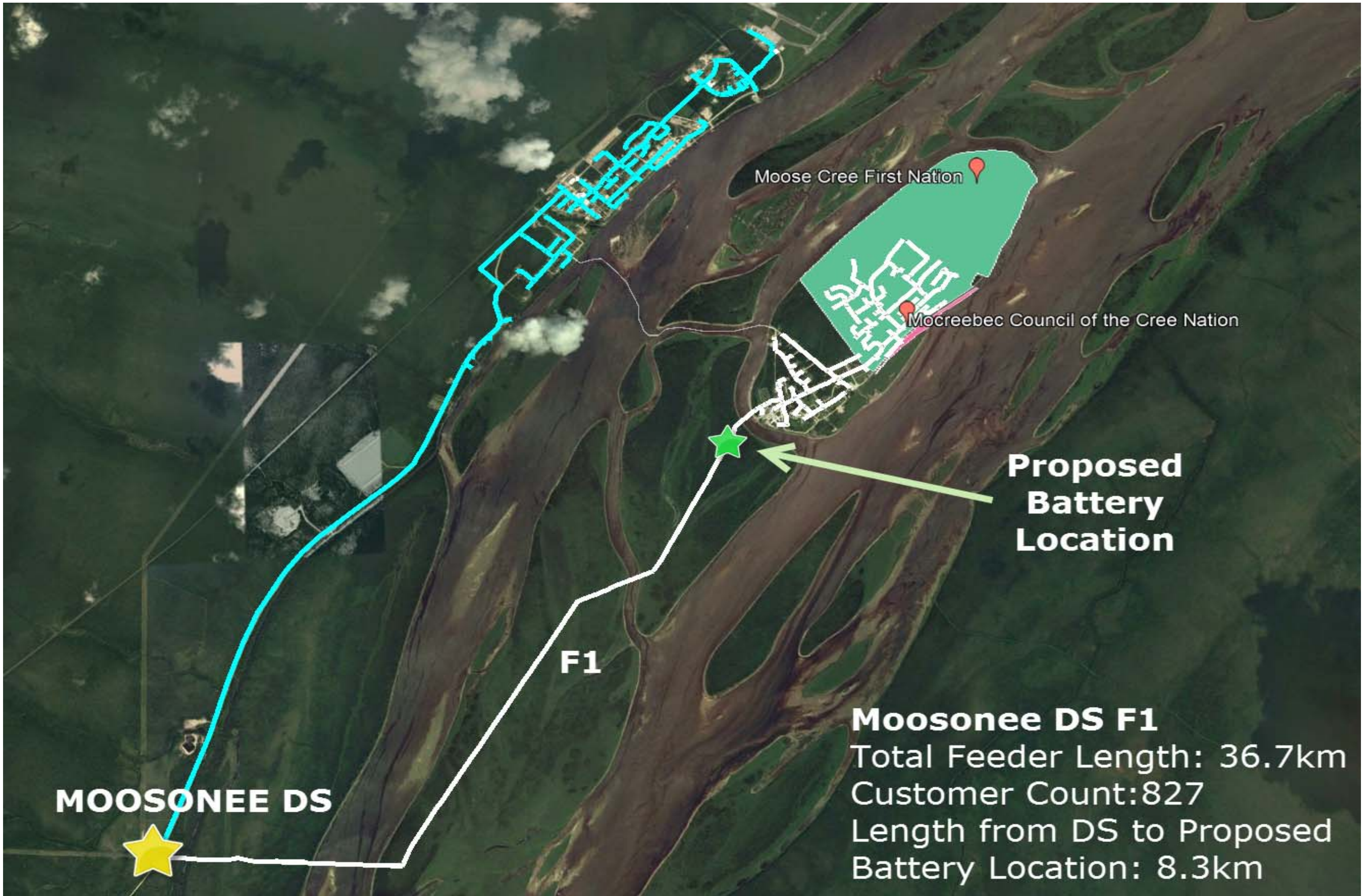
Moosonee DS F1/F3 Energy Storage Reliability Overview

Transmission Loss of Supply (LOS) Interruptions for Moosonee DS F1/F3 over 10 Years



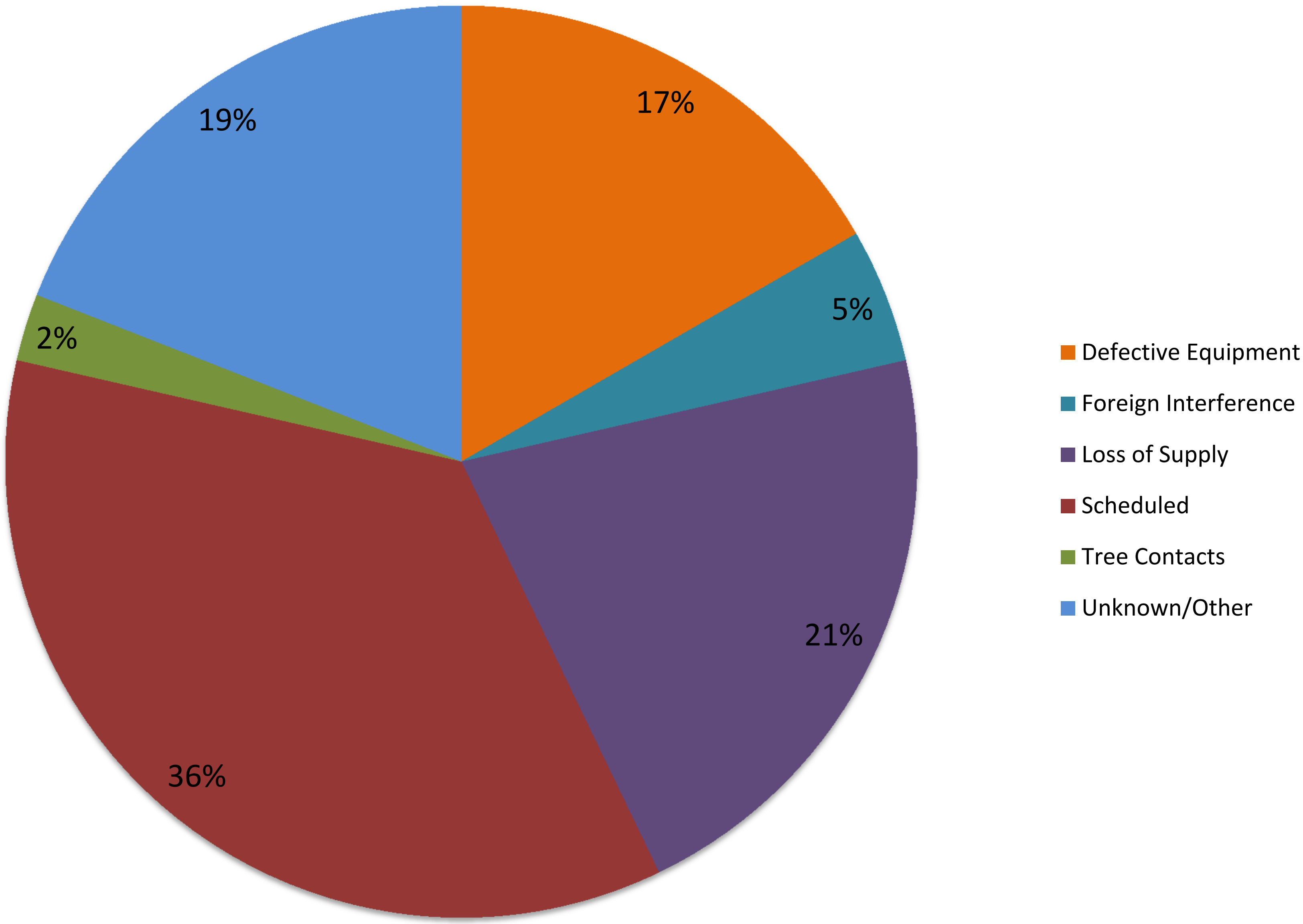
Note: 2018 data includes Jan. to Apr.

Moosonee DS F1



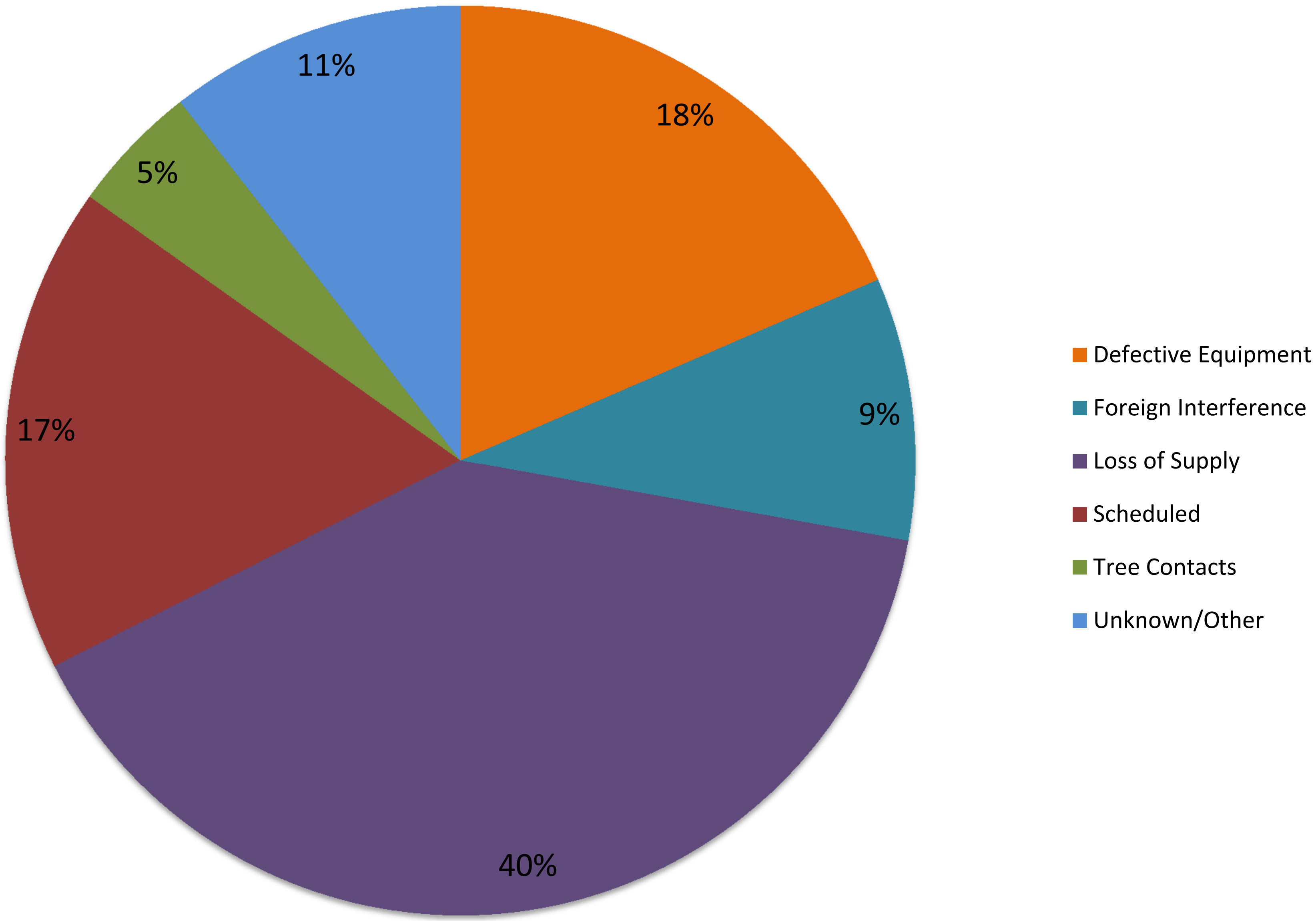
17

Moosonee DS F1: Frequency of Upstream Outages by Cause (5 years)



*Vegetation management will improve by 20-40% over the planning period.
** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F1: Duration of Upstream Outages by Cause (5 years)

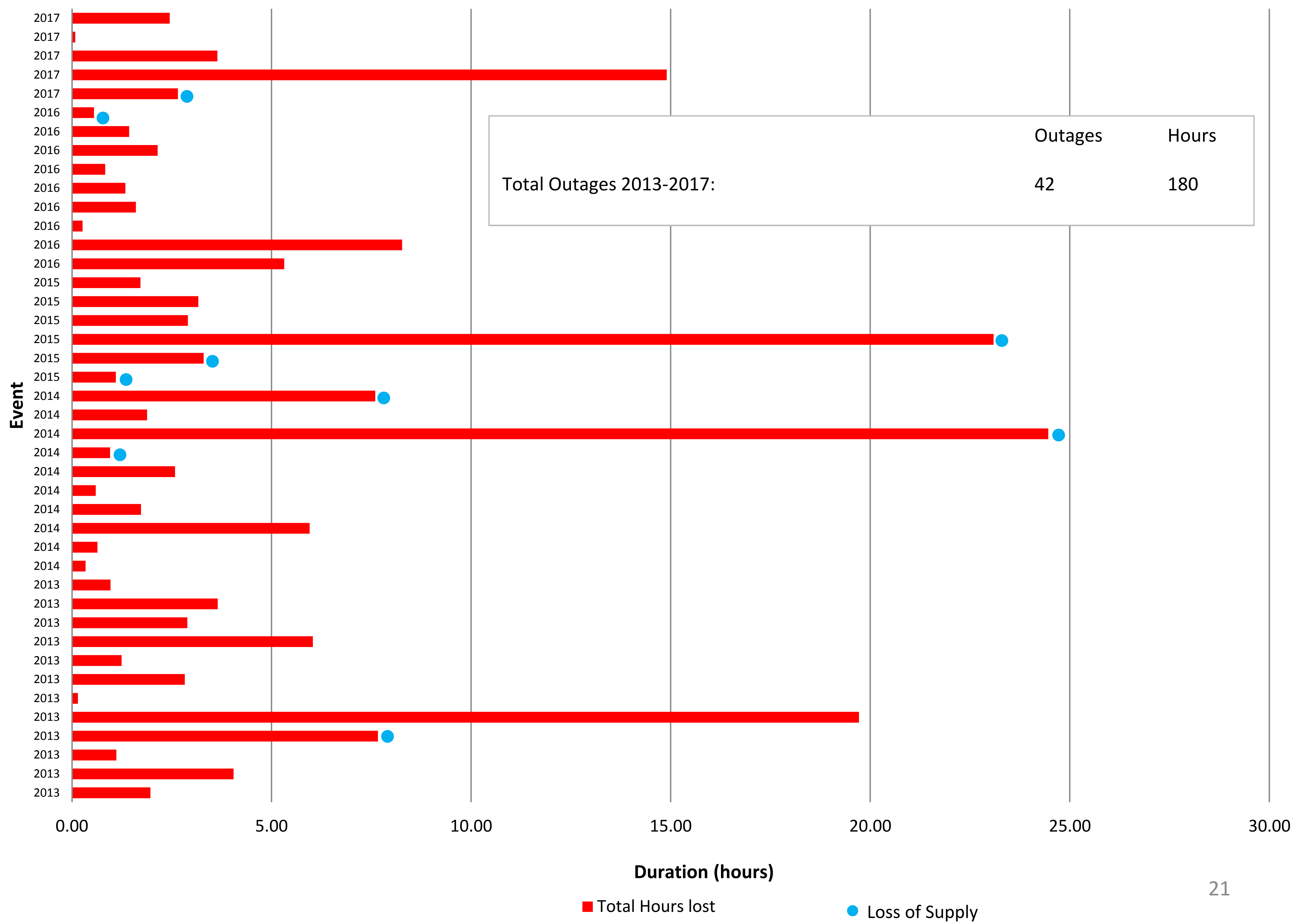


*Vegetation management will improve by 20-40% over the planning period.
** Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

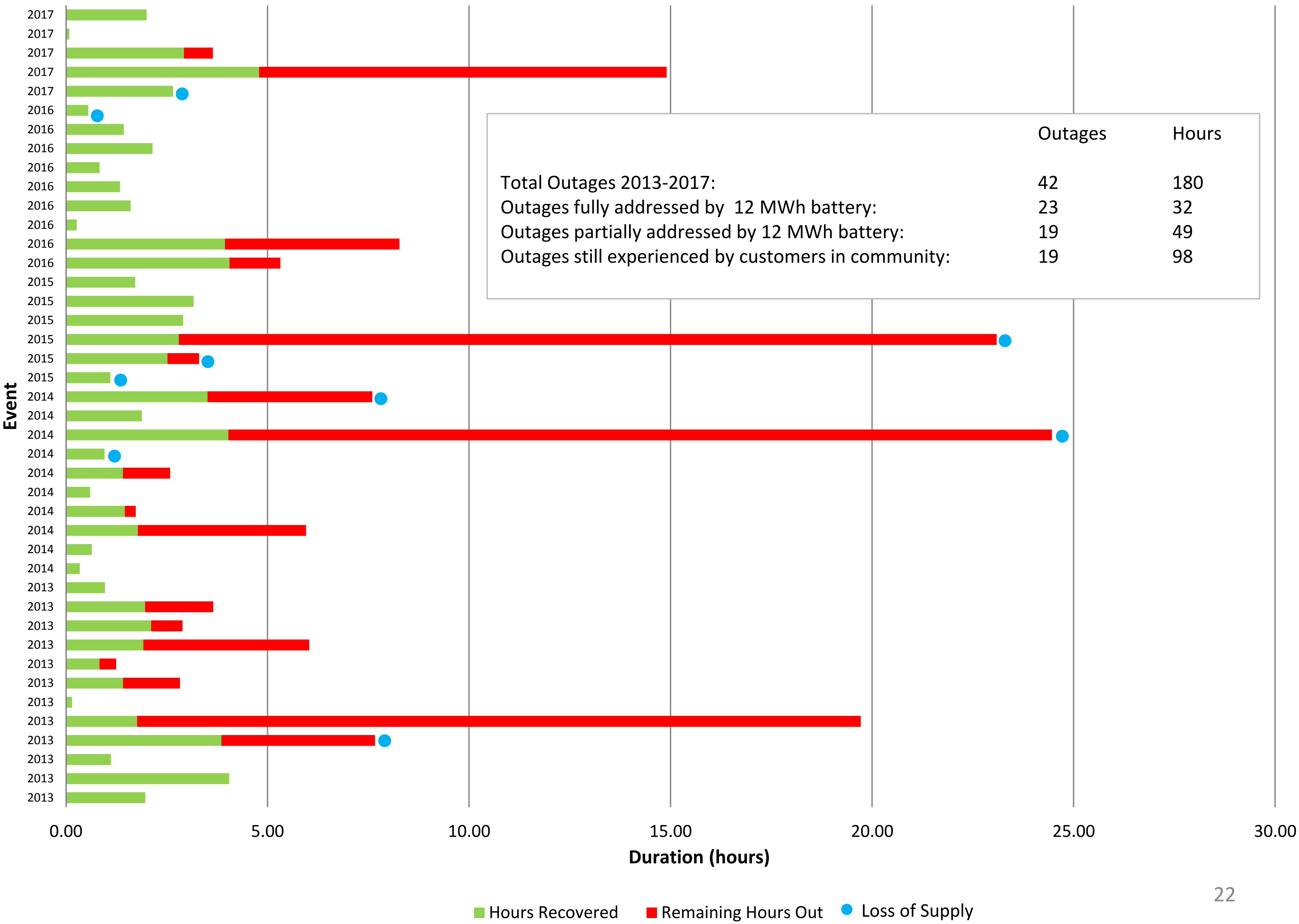
Moosonee DS F1 - Number and Total Duration of Outages by Year

Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	52
2014	10	47
2015	6	35
2016	9	22
2017	5	24

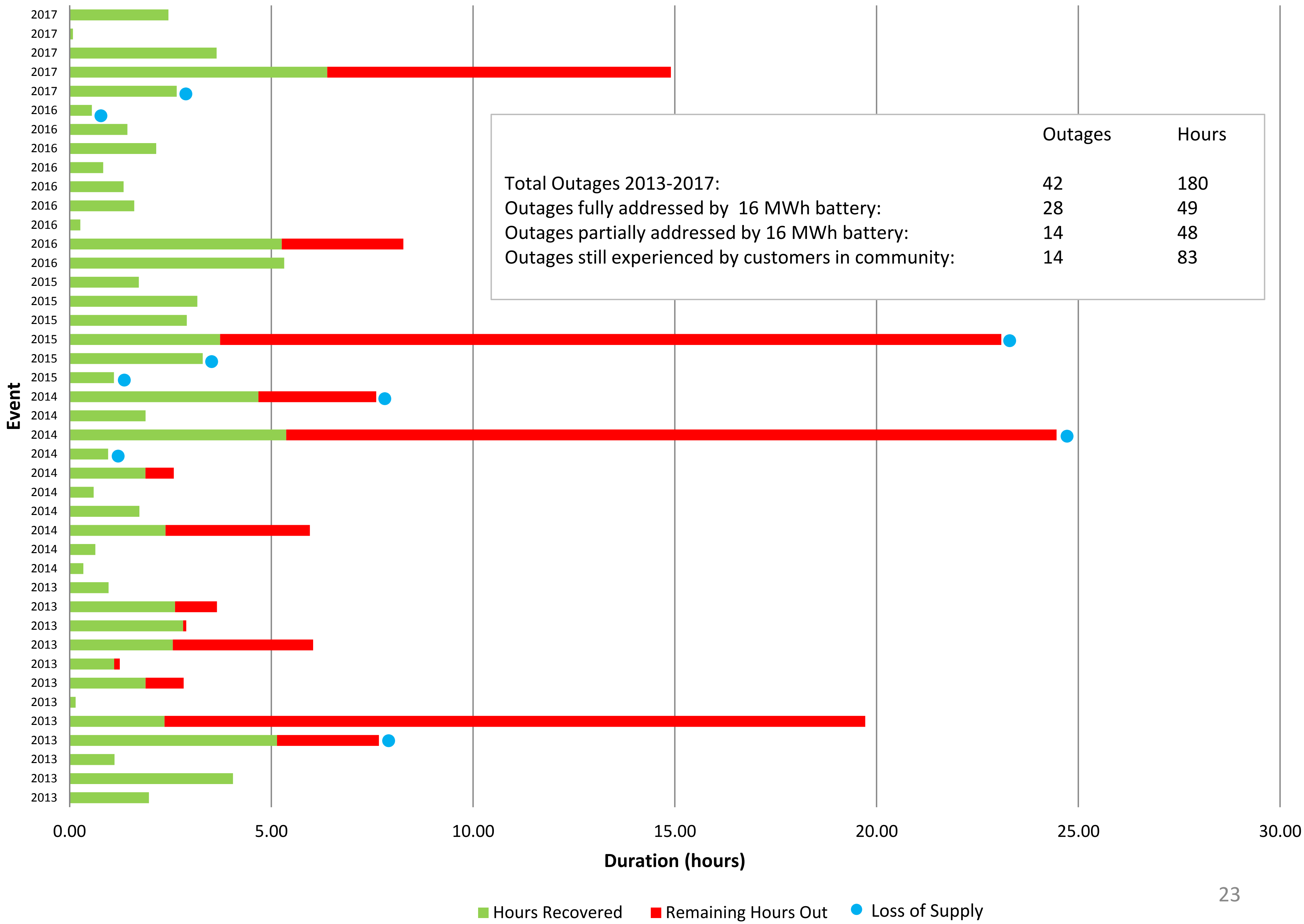
Moosonee DS F1: Outages Experienced Over Last 5 Years



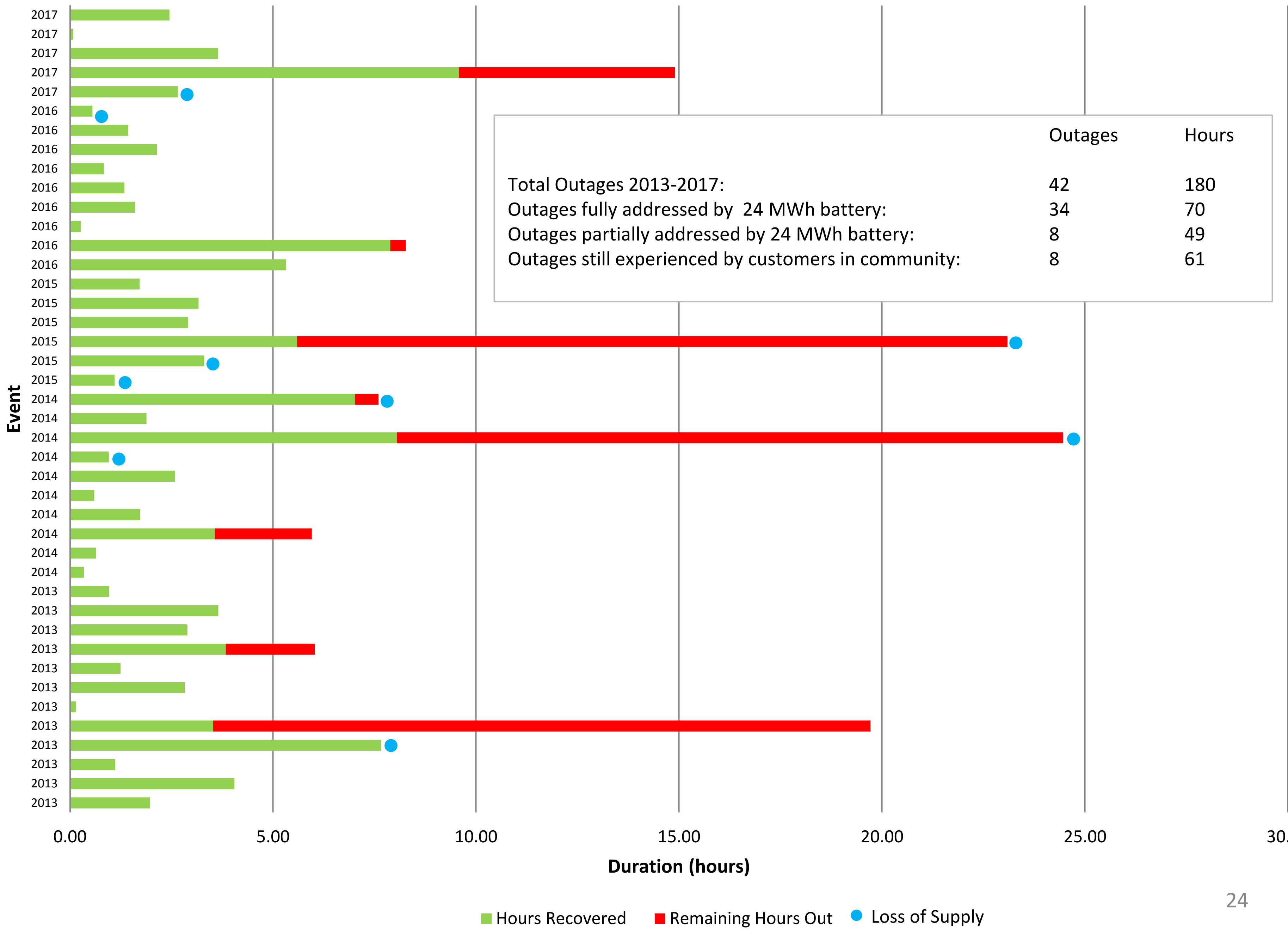
Moosonee DS F1: Outage Impact with 8MW, 12MWh energy storage ($18M)



Moosonee DS F1: Outage Impact with 8MW, 16MWh energy storage ($24M)

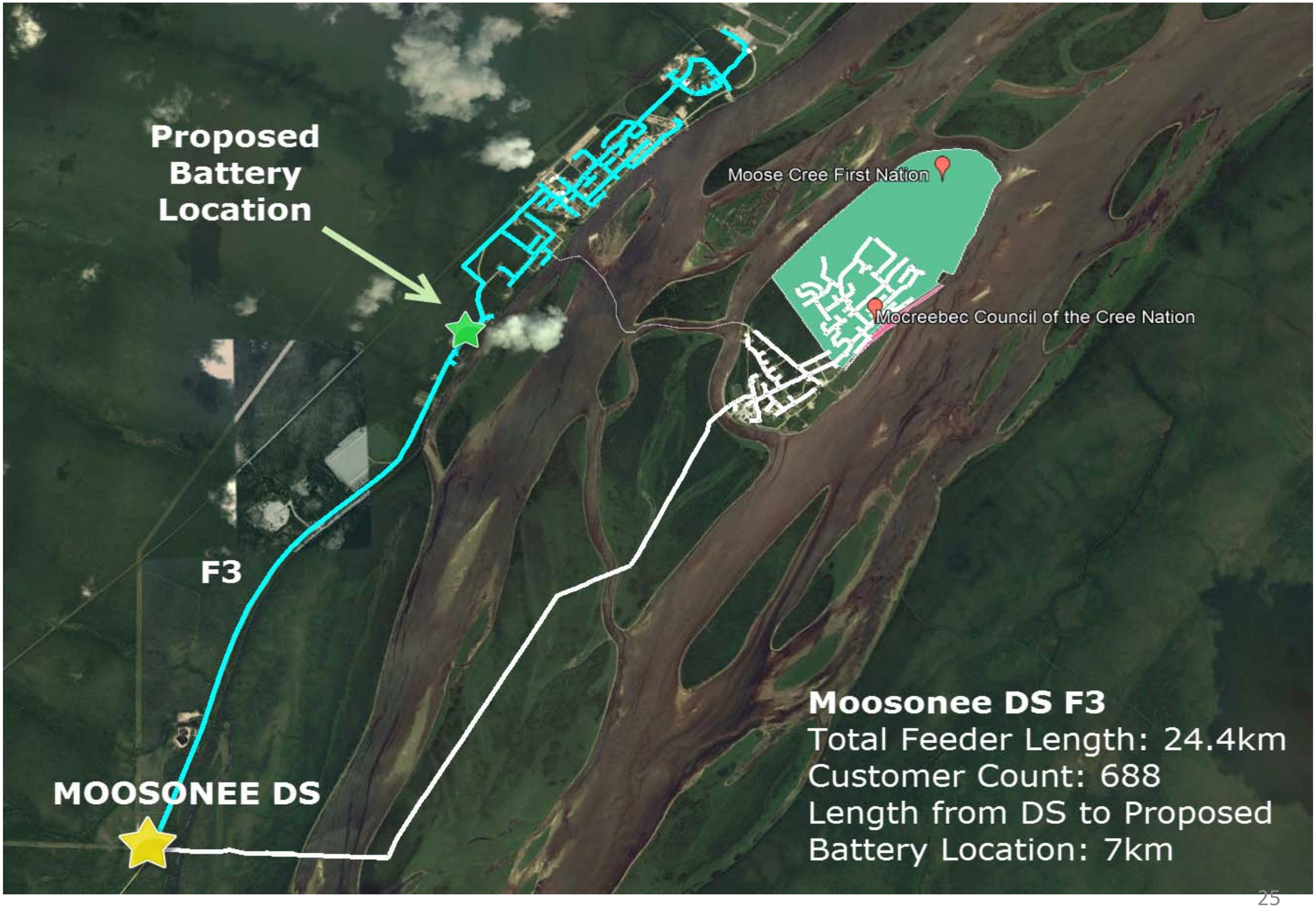


Moosonee DS F1: Outage Impact with 8MW, 24MWh energy storage ($36M)



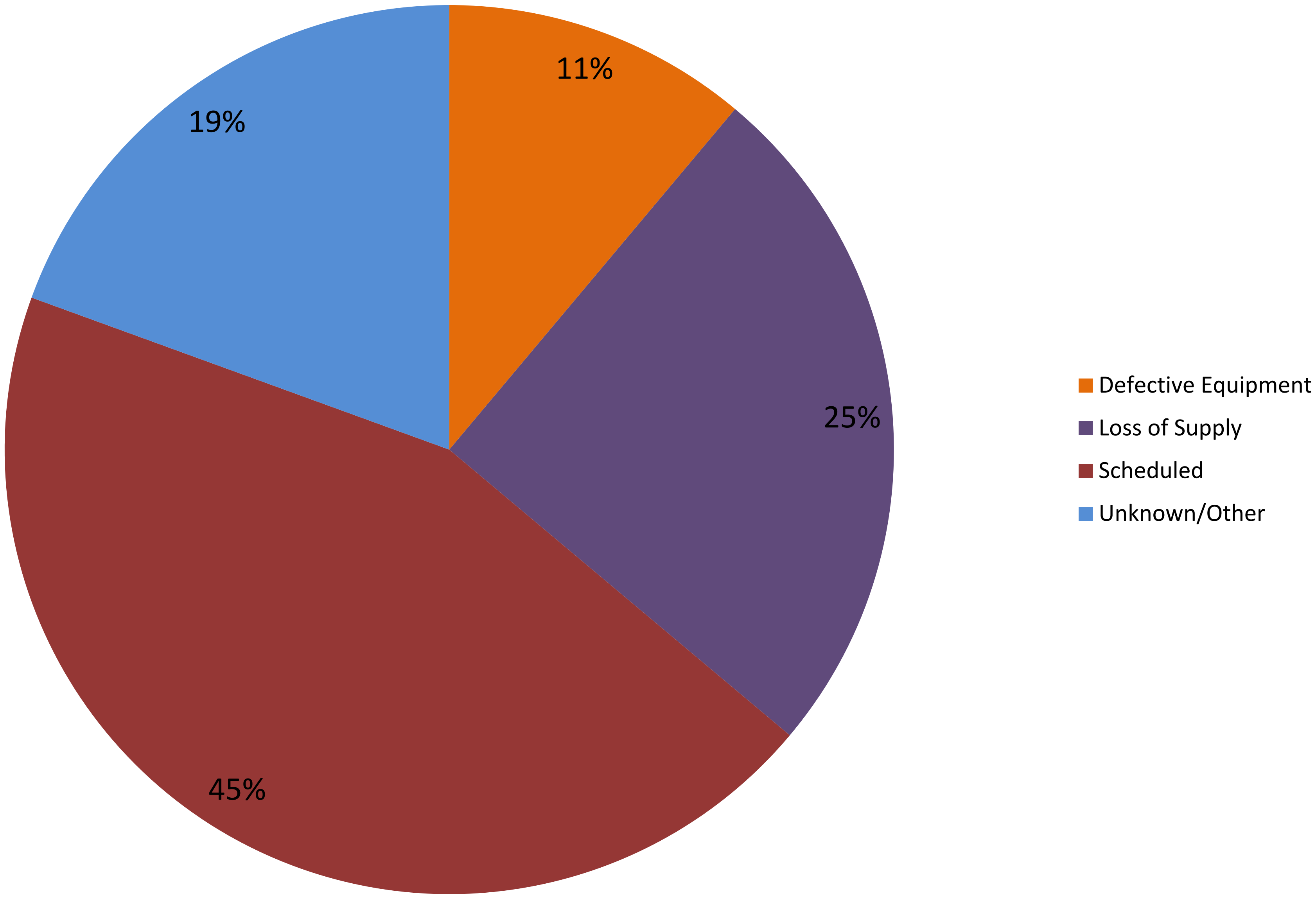
	Outages	Hours
Total Outages 2013-2017:	42	180
Outages fully addressed by 24 MWh battery:	34	70
Outages partially addressed by 24 MWh battery:	8	49
Outages still experienced by customers in community:	8	61

Moosonee DS F3



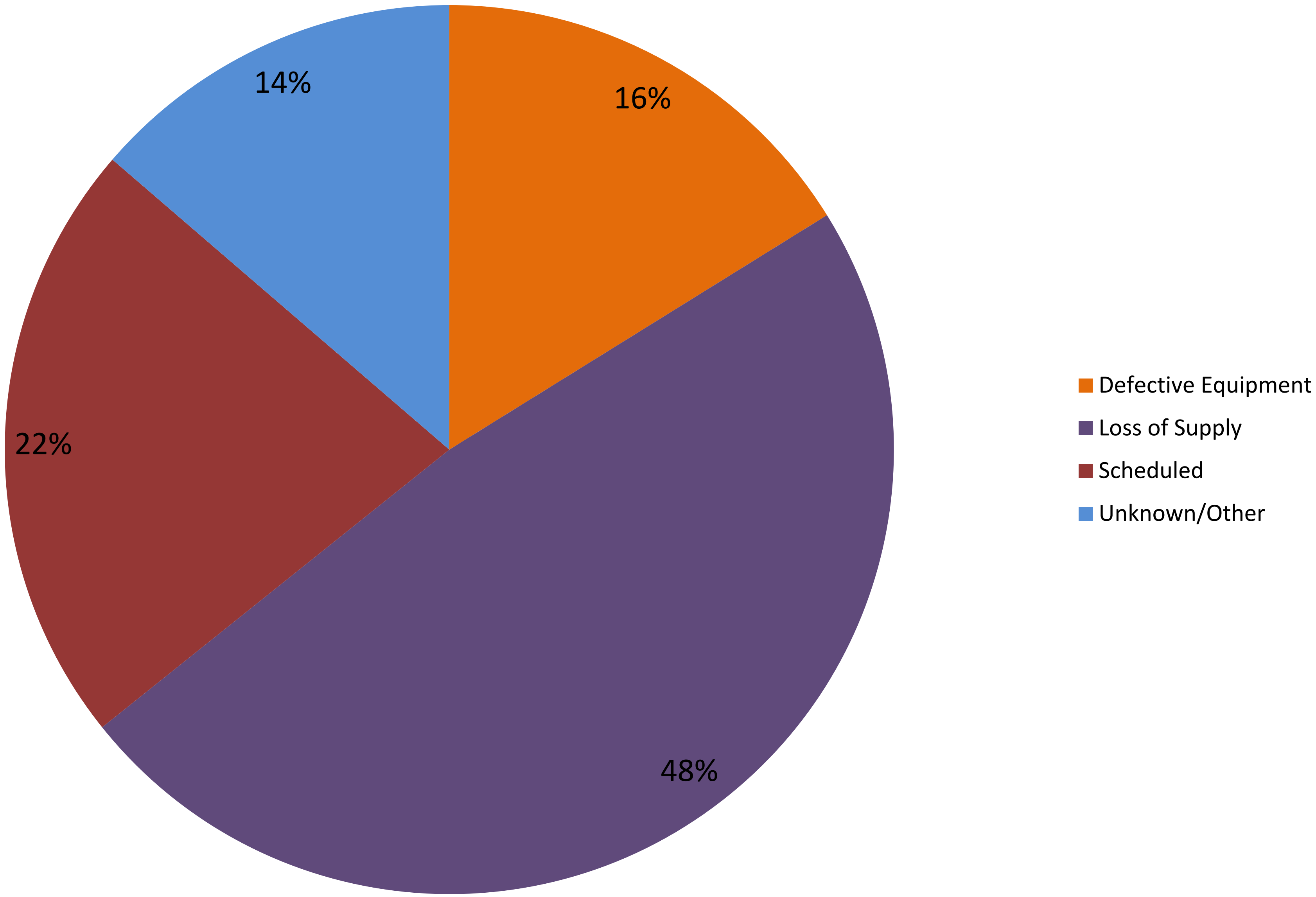
25

Moosonee DS F3: Frequency of Upstream Outages by Cause (5 years)



* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F3: Duration of Upstream Outages by Cause (5 years)

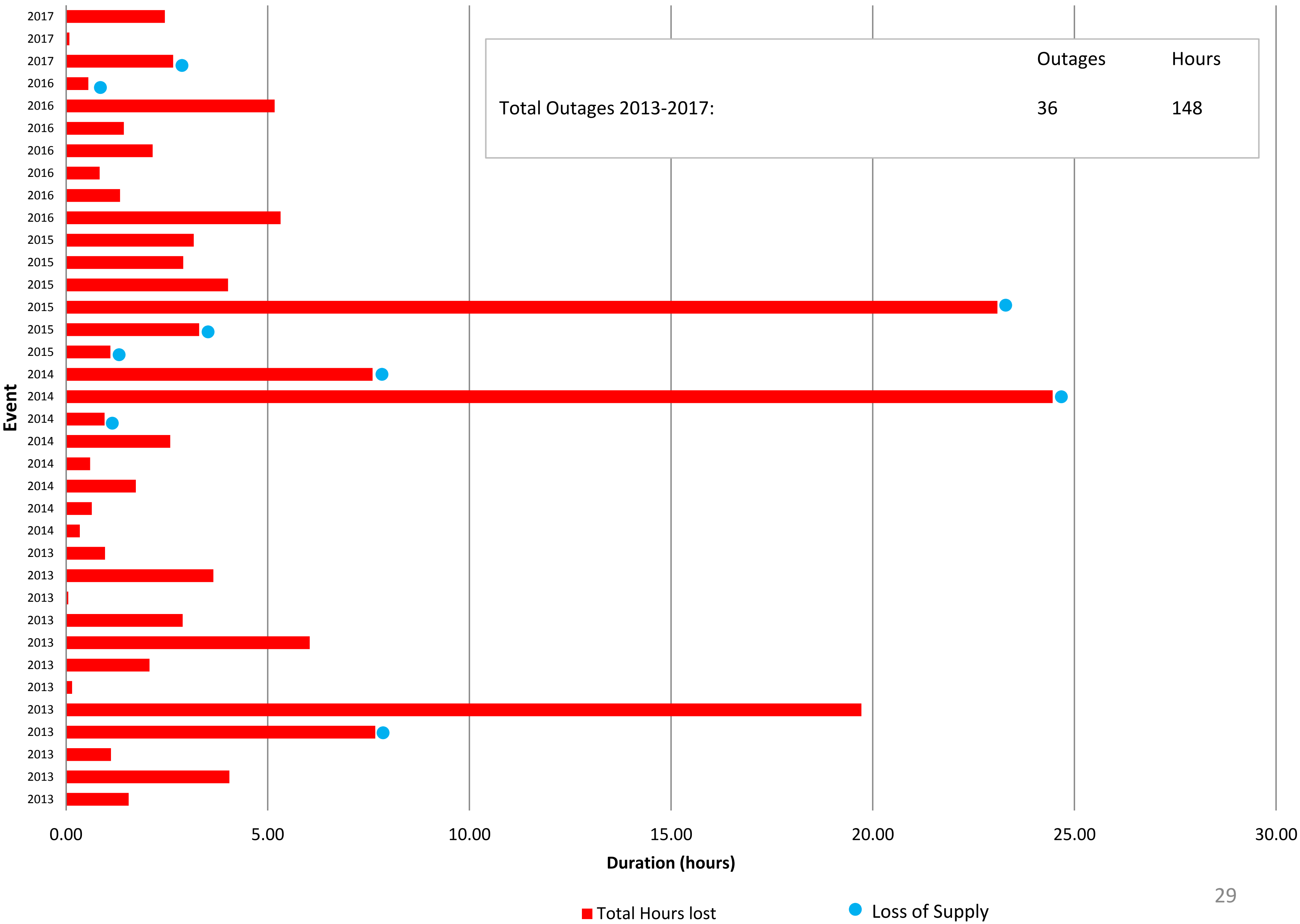


* Reduction in frequency of Loss of Supply is expected due to upstream transmission investments.

Moosonee DS F3: Number and Total Duration of Outages by Year

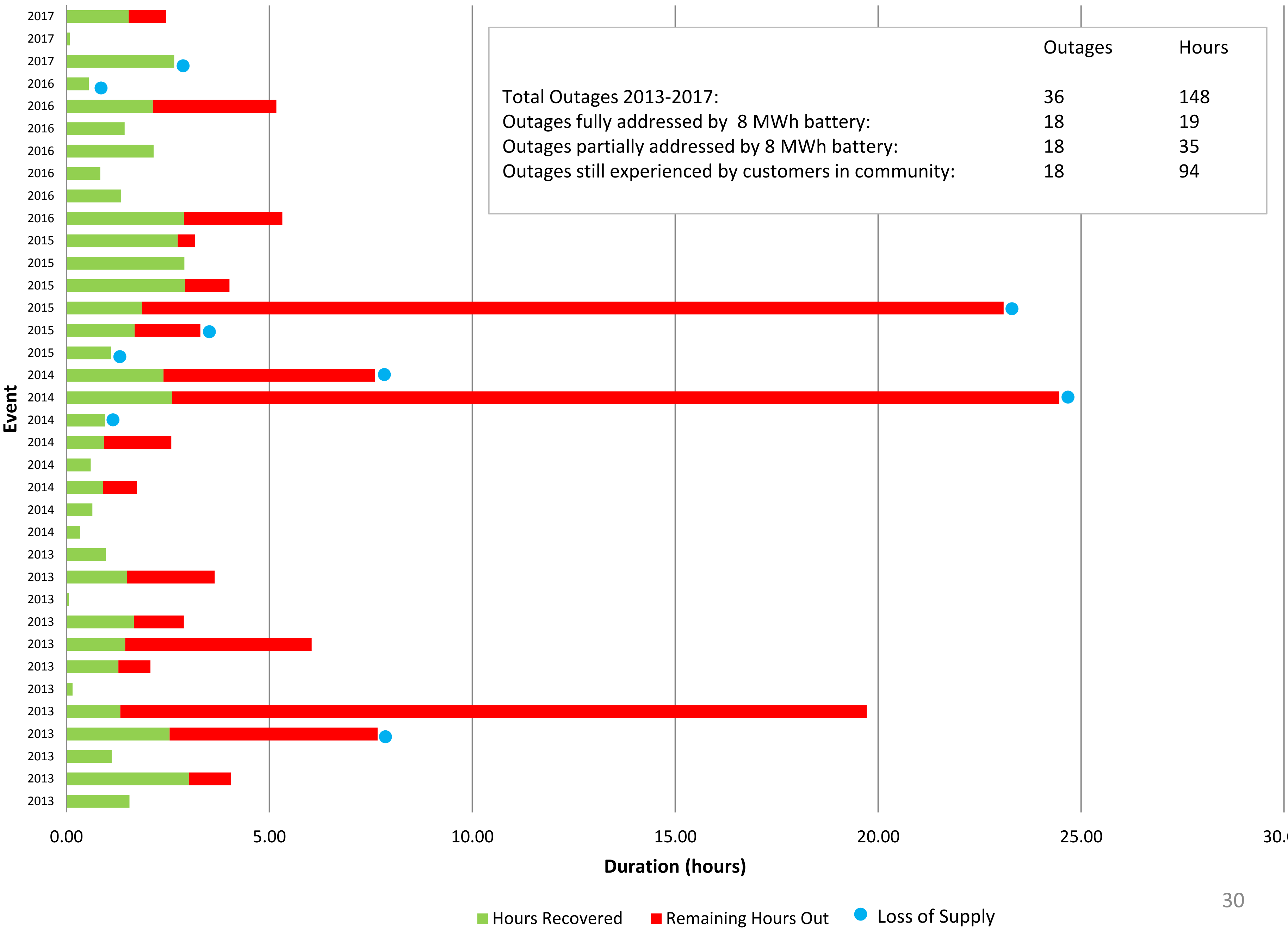
Year	Number of Outages	Total Duration of Outages (Hours)
2013	12	50
2014	8	39
2015	6	38
2016	7	17
2017	3	5

Moosonee DS F3: Outages Experienced Over Last 5 Years



29

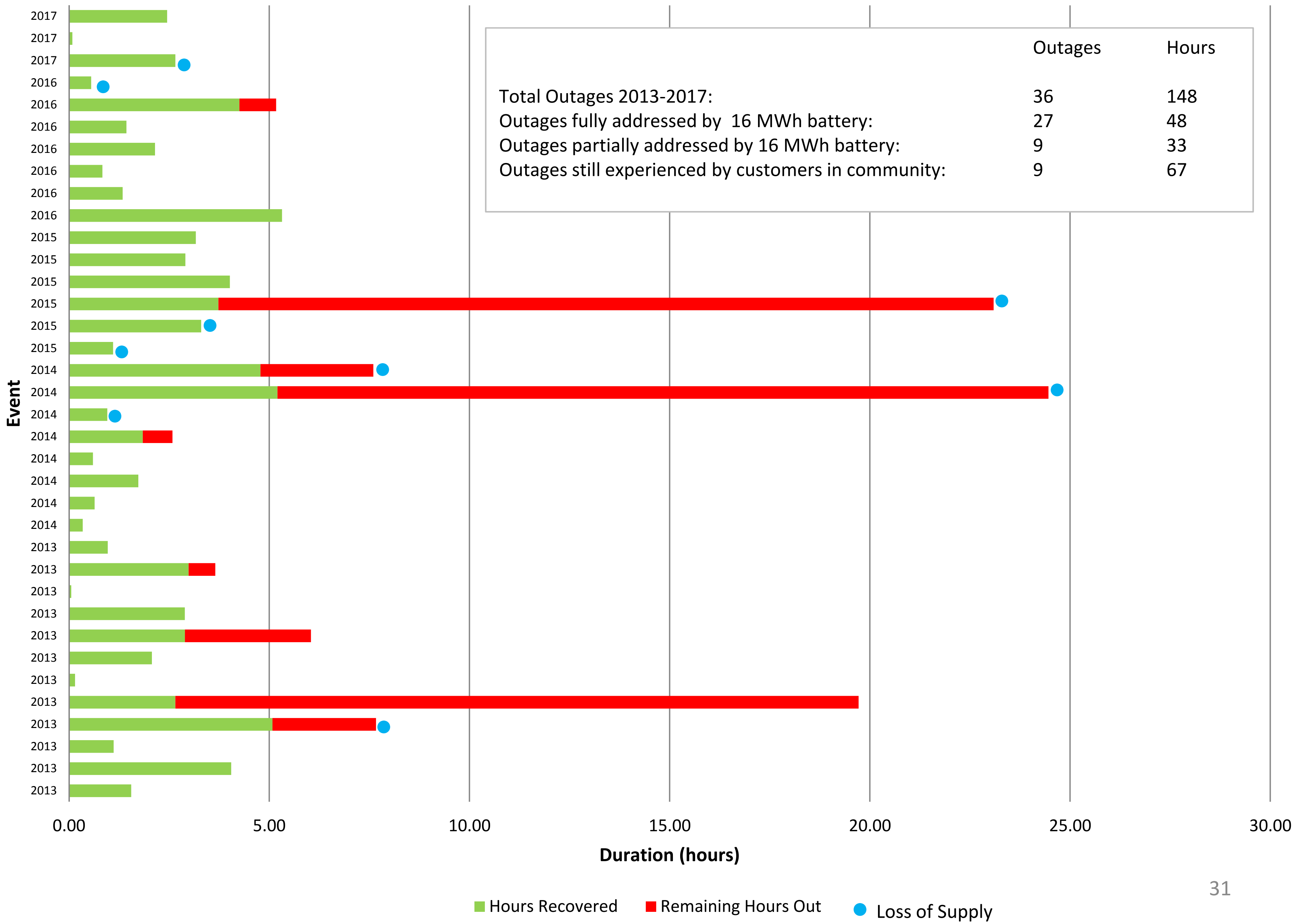
Moosonee DS F3: Outage Impact with 8MW, 8MWh energy storage ($12M)



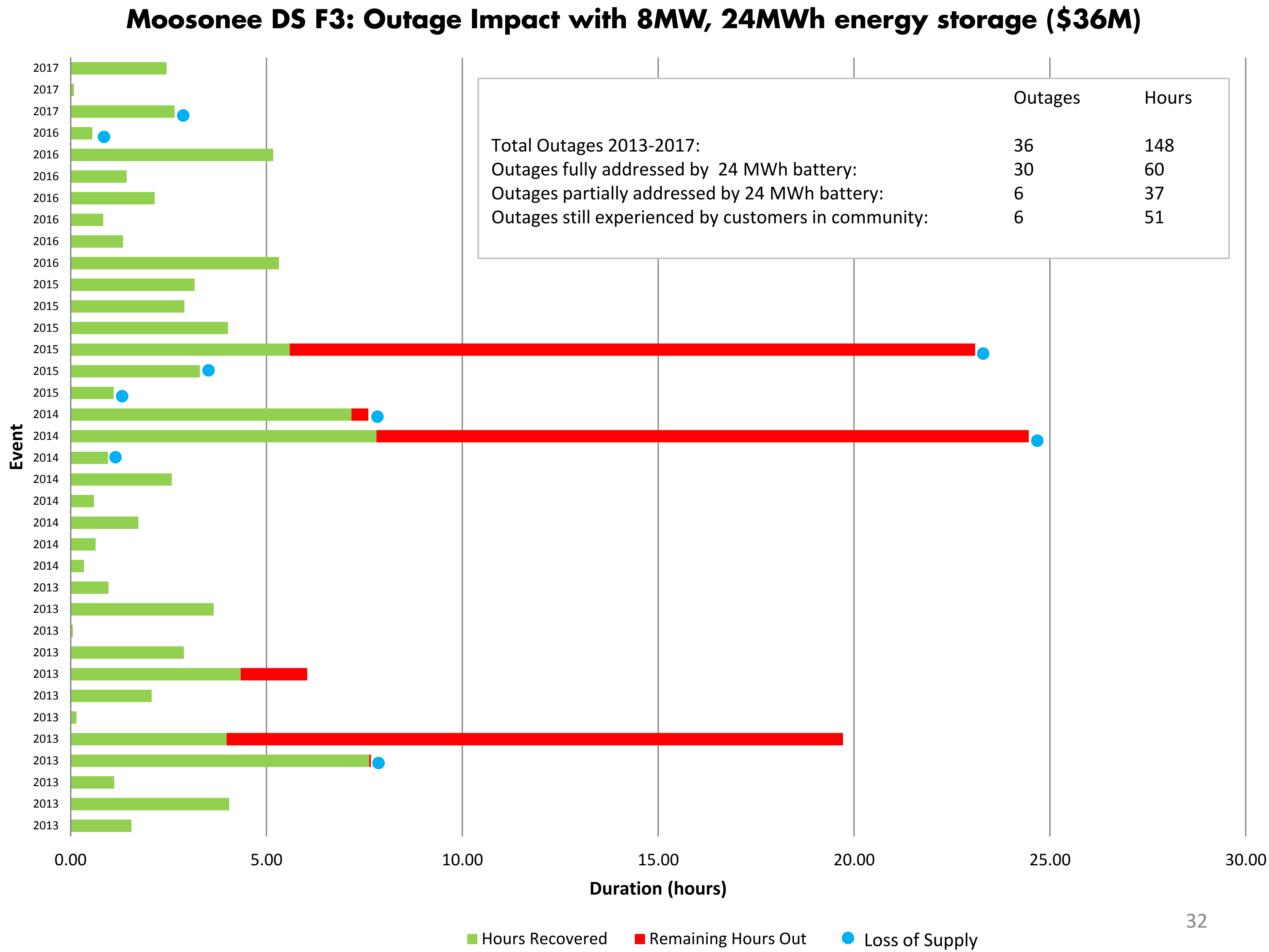
	Outages	Hours
Total Outages 2013-2017:	36	148
Outages fully addressed by 8 MWh battery:	18	19
Outages partially addressed by 8 MWh battery:	18	35
Outages still experienced by customers in community:	18	94

30

Moosonee DS F3: Outage Impact with 8MW, 16MWh energy storage ($24M)



31



Moosonee DS F3: Outage Impact with 8MW, 24MWh energy storage ($36M)
	Outages	Hours
Total Outages 2013-2017:	36	148
Outages fully addressed by 24 MWh battery:	30	60
Outages partially addressed by 24 MWh battery:	6	37
Outages still experienced by customers in community:	6	51
Event
2017
2017
2017
2016
2016
2016
2016
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2015
2015
2015
2015
2015
2015
2014
2014
2014
2014
2014
2014
2014
2014
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
2013
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Duration (hours)
Hours Recovered
Remaining Hours Out
Loss of Supply

32

Investment Prioritization

- Retention of an experienced storage and engineering partner is underway.
- The detailed engineering and financial viability review is targeted by September 30, 2018.
- There may be additional value due to scalability.
- Pilot project funding sourced through redirection ($5M) and may be offset or augmented by government funding programs.

TAB 3

Delivering a

POWERFUL FUTURE

HYDRO ONE LIMITED 2017 ANNUAL REPORT

hydro One

hydro One

Hydro One Limited (Hydro One) is Ontario's largest electricity transmission and distribution provider with more than 1.3 million valued customers, $25.7 billion in assets and annual revenues of approximately $6 billion. Our team of approximately 7,400 skilled and dedicated regular and non-regular employees proudly and safely serves suburban, rural and remote communities across Ontario through our approximately 30,000 circuit kilometres of high-voltage transmission and approximately 123,000 circuit kilometres of primary low-voltage distribution networks. Hydro One is committed to the communities we serve, and has been rated as the top utility in Canada for its corporate citizenship, sustainability, and diversity initiatives. We are one of only five utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association. We also provide advanced broadband telecommunications services on a wholesale basis utilizing our extensive fibre optic network. Hydro One's common shares are listed on the Toronto Stock Exchange (TSX: H).

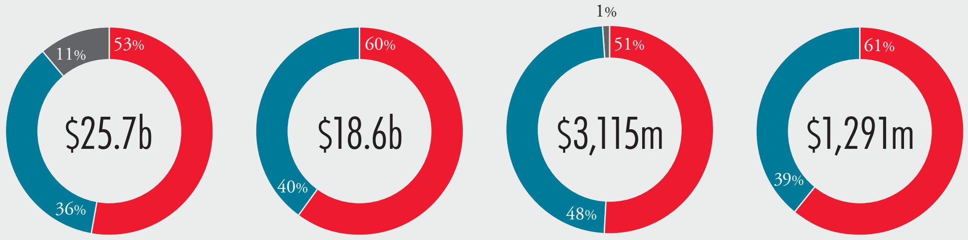
Contents

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

FINANCIAL HIGHLIGHTS

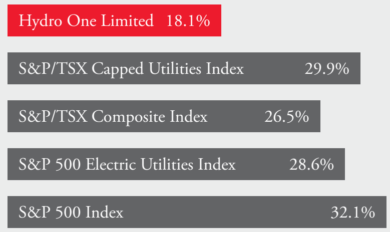
Year ended December 31 (millions of dollars, except as otherwise noted)	2017	2016
Revenues	**5,990**	6,552
Purchased power	**2,875**	3,427
Revenues, net of purchased power[1]	**3,115**	3,125
Operation, maintenance and administration costs (OM&A)	**1,066**	1,069
Depreciation and amortization	**817**	778
Financing charges	**439**	393
Income tax expense	**111**	139
Net income attributable to common shareholders of Hydro One	**658**	721
Basic earnings per common share (EPS)	**$1.11**	$1.21
Diluted EPS	**$1.10**	$1.21
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$1.17**	$1.21
Diluted Adjusted EPS[1]	**$1.16**	$1.21
Net cash from operating activities	**1,716**	1,656
Funds from operations (FFO)[1]	**1,579**	1,494
Capital investments	**1,567**	1,697
Assets placed in-service	**1,592**	1,605
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289
Debt to capitalization ratio[2]	**52.9%**	52.6%

Total Assets **Rate Base** **Revenues** (Net of purchased power costs) **Regulated Earnings** (Before financing charges and income taxes)



• Transmission • Distribution • Other

Total Shareholder Return (TSR)
November 5, 2015 IPO to December 31, 2017



1. See section Financial Report (starting on page 31) on "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.
2. Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

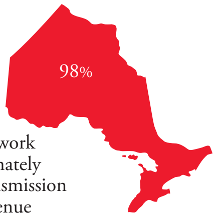
5 REASONS to Invest in Hydro One

INVESTING IN HYDRO ONE OFFERS A UNIQUE OPPORTUNITY TO PARTICIPATE IN THE TRANSFORMATION OF A PREMIUM LARGE-SCALE UTILITY

Nº 1

Everyone Uses Electricity
We are one of the largest regulated electric utilities in North America. We own and operate an extensive system of transmission and distribution networks in Canada's most populated province with no material exposure to commodity prices.

Our transmission network accounts for approximately 98% of Ontario's transmission capacity based on revenue



Nº 2

Strong Balance Sheet
Our strong investment-grade balance sheet has one of the highest quality utility credit profiles in North America.

Agency	Credit Profile Long Term/Short Term/Outlook
S&P	A / A-1/ negative
DBRS	A (high) / R-1 (low) / stable
Moody's	A3 / Prime-2 / negative

Nº 3

Predictable Growth
We offer a predictable multi-year growth profile with strong cash flows. This is the result of an expanding rate base that supports the need to upgrade and maintain our aging infrastructure.

Capital Investments
(CAD $ millions)

• Transmission • Distribution • Other

Nº 4

Attractive Dividend
We have an attractive dividend yield with 70–80 per cent target payout ratio and offer the opportunity for continued dividend growth.

70–80% TARGET PAYOUT RATIO

Nº 5

Forward Looking
Our highly accomplished management team has taken on the opportunity to transform the organization into a commercially oriented, performance-driven culture focused on improving productivity and customer service.

Reducing OM&A Spend
November 5, 2015 to December 31, 2017 (CAD $ millions)

CHAIR

David F. Denison
Chair of the Board
Hydro One Limited

Dear fellow shareholders,

As I look back on 2017, it is first important to acknowledge the tragic loss the Hydro One family suffered in December with the deaths of four employees. The response to that accident demonstrated the incredible strength and unity of the entire Hydro One organization as employees came together to mourn and support each other moving forward. It has also led to a re-affirmation of the paramount importance of safety in all aspects of our policies, practices and procedures.

During 2017, the Board worked closely with the management team to formulate a new long term strategy for Hydro One; our President and CEO Mayo Schmidt provides more detail about the strategy in his letter. The Board is confident that the disciplined execution of this strategy in the years ahead will create considerable value for our shareholders and other stakeholders. The pending acquisition of Avista Corporation that we announced last July is just one concrete example of the implementation of that strategy.

Successful execution relies on a talented management team. One of the key responsibilities and priorities for our Board is to ensure that we have sufficient depth of talent and experience as well as strong succession plans across our leadership team. The Board was pleased to see the ranks of our leadership team strengthened with the recently announced addition of Paul Dobson as Chief Financial Officer.

Commitment to Diversity and Inclusion
Last year, Hydro One joined the 30% Club, an international campaign aimed at achieving a minimum of 30 per cent of women represented on boards, a level we have already surpassed, and also signed the Catalyst Accord: Women on Corporate Boards in Canada. In August, Hydro One also became a signatory to the Leadership Accord on Gender Diversity in the Canadian Electricity Industry.

All of these initiatives demonstrate Hydro One's commitment to becoming a more diverse and inclusive workplace, one where all employees feel supported and included.

In conclusion, 2017 was an important year of transition for Hydro One in its evolution as a broadly held, strong performing public Company. The entire Board expresses its thanks and appreciation to all employees of Hydro One for their hard work in serving the interests of our customers and shareholders. We believe we now have the foundations in place to enhance the value we will bring to all stakeholders in the years ahead.

Thank you for your investment and continued support,

David F. Denison
Chair of the Board of Directors

Hydro One's Governance Practices

Fully Independent Board (excluding CEO)	Separate Board Chair and CEO	Director Share Ownership Guidelines	Commitment to Director Diversity	Governance Agreement with the Province	Majority Voting Policy for Directors	Annual Reviews of Board and Committee Performance

CEO

Mayo Schmidt
President and Chief Executive Officer
Hydro One Limited

Key Achievements

\$114.4m
2016/2017 productivity savings[1]

5%
Dividend increase in May (to \$0.22)

41% (approx.)
Transmission SAIDI[2] improvement

1st
Hydro One's Contact Centre was the first electricity service provider in Ontario to open to customers on Saturdays

90%
Customer satisfaction with contact centre agents; highest in the Company's history

1. Productivity savings achieved are as a result of operational improvements in both capital and OM&A.
2. SAIDI (System Average Interruption Duration Index) year-end 2017 performance improvement relative to a 5-year average (%).

Dear fellow shareholders,

I want to acknowledge the tragic loss we experienced on December 14th that took the lives of four of our own. The entire Hydro One family came together for the families and to support teammates in the wake of this tragedy and to commemorate the lives of James, Jeff, Darcy and Kyle. Collectively, we continue to support the grieving families and loved ones of our four men. The health, safety, and well-being of every single person at Hydro One are paramount to me, this Company, and to all of our people.

While we were also faced with a number of industry challenges including: rising interest rates, a lower regulated return on equity that impacted transmission and distribution revenues and extended unseasonably milder weather affecting 2017 total shareholder return; we have acted with a high degree of discipline to moderate these events and we remain committed to delivering value for our shareholders and other stakeholders.

Unveiling Our Strategy
In 2017, our Board of Directors approved Hydro One's strategy which outlines our plan to become one of North America's leading utilities.

1. Optimization and Innovation
2. Diversification
3. Growth

In 2015, our public listing was the fourth largest IPO in Canadian history. While Hydro One is now a commercially focused shareholder-owned company, we embrace the responsibility of delivering results for shareholders while caring for our people and building our customer oriented culture.

Privatization has made it possible for us to enact powerful change at Hydro One: improved customer service, acting on efficiency and productivity opportunities, and greater corporate social responsibility. We have attracted a market-leading team of professionals to drive Hydro One to further successes. As shareholders, you have the unique opportunity to participate in our transformation and to invest in a premium, large-scale utility.

In 2016, on behalf of our 1.3 million customers, we advocated to the provincial government about the need for rate relief for Customers. We inspired and led the electricity utility industry in our province to proactively reconnect vulnerable customers before the coldest months of the year. Following our lead, in October 2017, the Ontario Energy Board (OEB) announced that all electric distribution companies operating in Ontario would be required to reconnect power for vulnerable individuals and families in the winter.

2017 Accomplishments
Optimization and Innovation: We have delivered approximately \$114.4 million in productivity savings in 2016 and 2017. We continue to review processes and implement initiatives across our entire platform to drive efficiencies and generate cost savings as our contribution to critical infrastructure.

Application of technology in the field, and the elimination of a paper-based system through Move-to-Mobile has provided our people with the necessary tools to optimize both volume and quality of service. Fleet telematics led to a net reduction of hundreds of units in our fleet, while improving safe driving and reducing costs.

We have designed and implemented a new vegetation maintenance strategy and program called the Optimal Cycle Protocol transitioning from a 10 year cycle to a 3 year maintenance cycle to reduce safety risks, improve reliability, reduce unit cost, and improve customer satisfaction.

Customer Focus: We achieved the lowest accounts receivable balance in our history – a \$40 million reduction, while achieving a reduction in customer disconnections for non-payment declining by 57% in 2017.

Through the Province's Fair Hydro Plan, a typical Hydro One residential customer will see savings on their monthly bills, of 31 per cent. We have seen significant improvement, in customer service statistics this past year, including:

- The highest customer satisfaction rate in four years for our distribution customers; and
- 10 per cent increase in transmission customer satisfaction.

Diversification: The electricity industry is transforming from a system based on large centralized generation, transmission and distribution, to a localized distributed generation systems to leverage capacity. In anticipation of this, Hydro One is developing its strategy to adapt our grid investments to reflect this new reality, and to provide new energy services that customers are demanding.

Growth: We announced our intention to acquire Avista Corporation (Avista) to create a growing North American utility leader with a combined pro forma asset value of over CAD \$34.9 billion. With Avista, Hydro One is strengthening its core by diversity of geography, regulation and service offerings to include gas distribution in a vertically integrated platform.

I would like to thank the thousands of Hydro One employees across Ontario who are committed to advocating on behalf of our customers. I also extend my gratitude to our Board of Directors for its support and confidence in Hydro One's leadership team.

Sincerely,

Mayo Schmidt

Mayo Schmidt
President and Chief Executive Officer

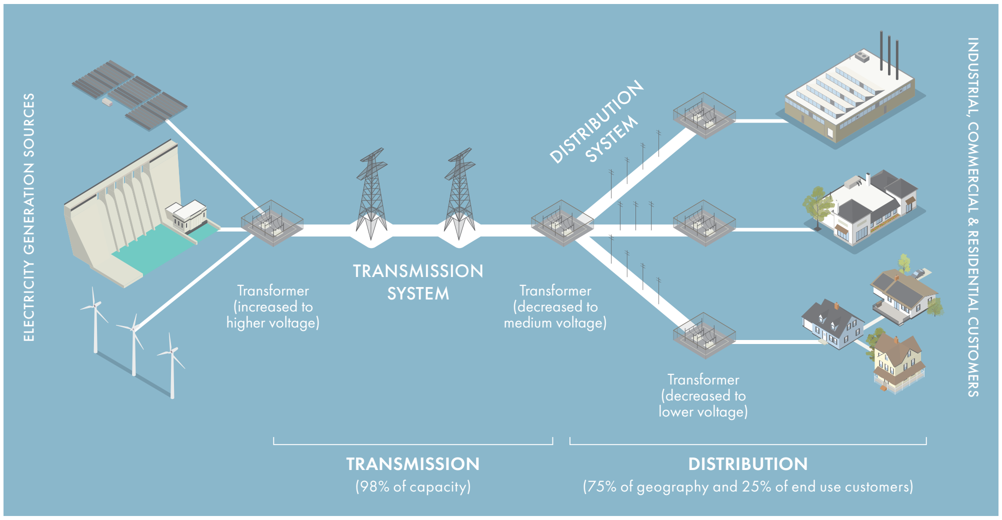
AT-A-GLANCE

ONE OF NORTH AMERICA'S LARGEST ELECTRIC UTILITIES[1]

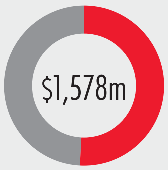
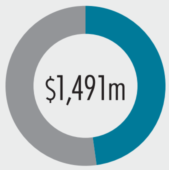
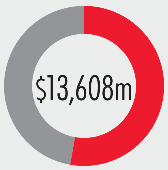
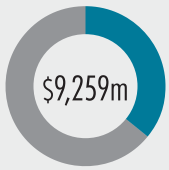
Our transmission and distribution system safely and reliably serves communities throughout Ontario. Our customers are suburban, rural and remote homes and businesses across our province.

We proudly own and operate $25.7 billion in assets and have annual revenues of approximately $6 billion.

Hydro One's Role in the Electric Power System



OUR BUSINESSES

	Transmission	Distribution	Other
Revenues (Net of Purchased Power)	 51%	 48%	 1%
Regulated	✓	✓	Unregulated
Segmented Assets	 53%	 36%	 11%
Business Description	Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to our distribution company and industrial customers across Ontario.	The Hydro One distribution system is the largest in Ontario. It consists of approximately 123,000 circuit kilometres of primary low-voltage power lines serving over 1.3 million customers.	Consists of a telecommunications business and certain corporate activities. Hydro One Telecom offers organizations a diverse, secure and highly reliable broadband connectivity solution.
Customer Segments	• Large directly connected industrial customers • Local distribution companies • Generators	• Residential and business customers • Municipal utility customers	• Data centres • Cloud service providers • Telecommunications services and public sector entities • Internet service providers • Enterprises

1. Based on assets

Key Highlights 2017

7,400 (approx.)
Skilled and dedicated regular and non-regular employees

over 1.3 million
Valued customers

$1.6b (approx.)
Capital investments

308
Transmission stations in service

$18.6b
Combined transmission and distribution rate base

30,000 (approx.)
Circuit kilometres of high-voltage transmission lines

1 of 5
Utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association

123,000 (approx.)
Circuit kilometres of primary low-voltage distribution lines

MAJOR PROJECTS

	Supply to Essex County Transmission Reinforcement	Clarington Transmission Station	East-West Tie Station Expansion
			
Description	Hydro One is constructing a new transmission station in the Municipality of Leamington and a 13-kilometre, double circuit 230 kilovolt transmission line on a new corridor to connect the station with the existing 230 kilovolt transmission line. The project is needed to provide for load growth in the Kingsville-Leamington area and to improve operational flexibility in the Windsor-Essex region in the long term.	Clarington Transmission Station involves the construction of a new 500/230 kilovolt transformer station in the city and the connection of the existing 230 kilovolt and 500 kilovolt transmission lines in the area. The station is required to ensure an adequate, safe and reliable supply of power to support the growing communities in the eastern part of the Greater Toronto Area.	Hydro One is performing station upgrades to our Wawa and Lakehead transmission stations. The upgrades are necessary to support the East-West Tie Line project, a priority project in the Province of Ontario's Long-Term Energy Plan.
Estimated Total Project Cost	$57[1] million	$267 million	$157 million
Capital Cost to Date	$52 million	$223 million	$7 million
Anticipated In-Service Date	2018	2018	2021

1. In February 2018, the estimated cost to complete the supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million

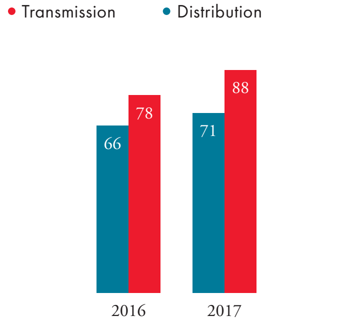
CUSTOMER FOCUS

We made great strides in 2017 to become our customers' advocates. The Hydro One of today aspires to be a more thoughtful, caring organization where the voices of our more than 1.3 million customers are heard and acted on.

Distribution Customer Satisfaction
Increased to 71 per cent in 2017, an increase of 5 per cent since 2016, largely due to strong operational performance in all functional areas, including billing, contact centre, collection and conservation.

Transmission Customer Satisfaction
Increased to 88 per cent in 2017, an increase of 10 per cent since 2016, partially attributed to enhanced customer reporting and a renewed commitment to customer advocacy.

Customer Satisfaction (%)



OUR STRATEGY FOR SUCCESS

1. OPTIMIZATION AND INNOVATION

Hydro One is transforming to achieve its vision of becoming a best-in-class, customer-centric commercial entity, with a culture of operational excellence and continuous improvement. Hydro One will execute on its strategy to transmit and distribute electricity safely and reliably in a manner that produces the greatest value for customers. Hydro One seeks to be excellent in every facet of its operations, to the benefit of its customers, employees and shareholders.

Innovation will become a focus for the Company and Hydro One plans to invest in innovation to modernize the transmission and distribution grids, improving reliability and efficiencies as well as building a platform for connecting distributed energy resources.

Move to Mobile (M2M) – The M2M project transformed work processes and implemented technology that automated the scheduling & dispatching functions, including the deployment of tablets to the field for work tracking resulting in enhanced customer service and productivity gains.

Procurement – A comprehensive spend analysis was performed in 2017. Strategic sourcing initiatives led to price reduction for materials and services as a result of consolidating spend across the Company and increasing competition among vendors.

Fleet Right Sizing – In 2017 the Hydro One fleet (transportation & work equipment was reduced by 10 per cent by leveraging telematics data that identified underutilized fleet equipment.

Optimal Cycle Protocol (OCP) – In October 2017, a state-of-the-art vegetation management program was introduced. The OCP program involves a shorter tree clearing and trimming cycle where crews focus on defects along Hydro One's vast distribution line every three years rather than full right-of-way management every eight to 10 years. In 2017, 45 per cent of outages were because of trees.

Tackling Distribution Reliability – Two primary programs will result in improved reliability. The OCP program and Distribution grid modernization both will impact reliability positively over the next few years.

Procurement

$29.5m

in procurement savings (2017)

Move-to-Mobile

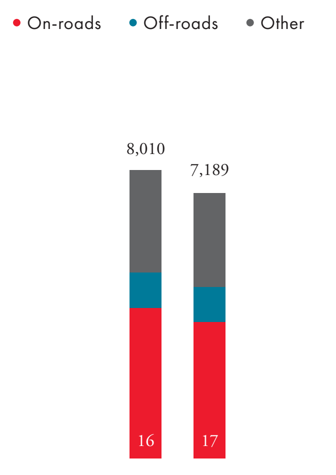
$16.9m

in savings (2017)

Fleet

10%

net reduction of number of fleet

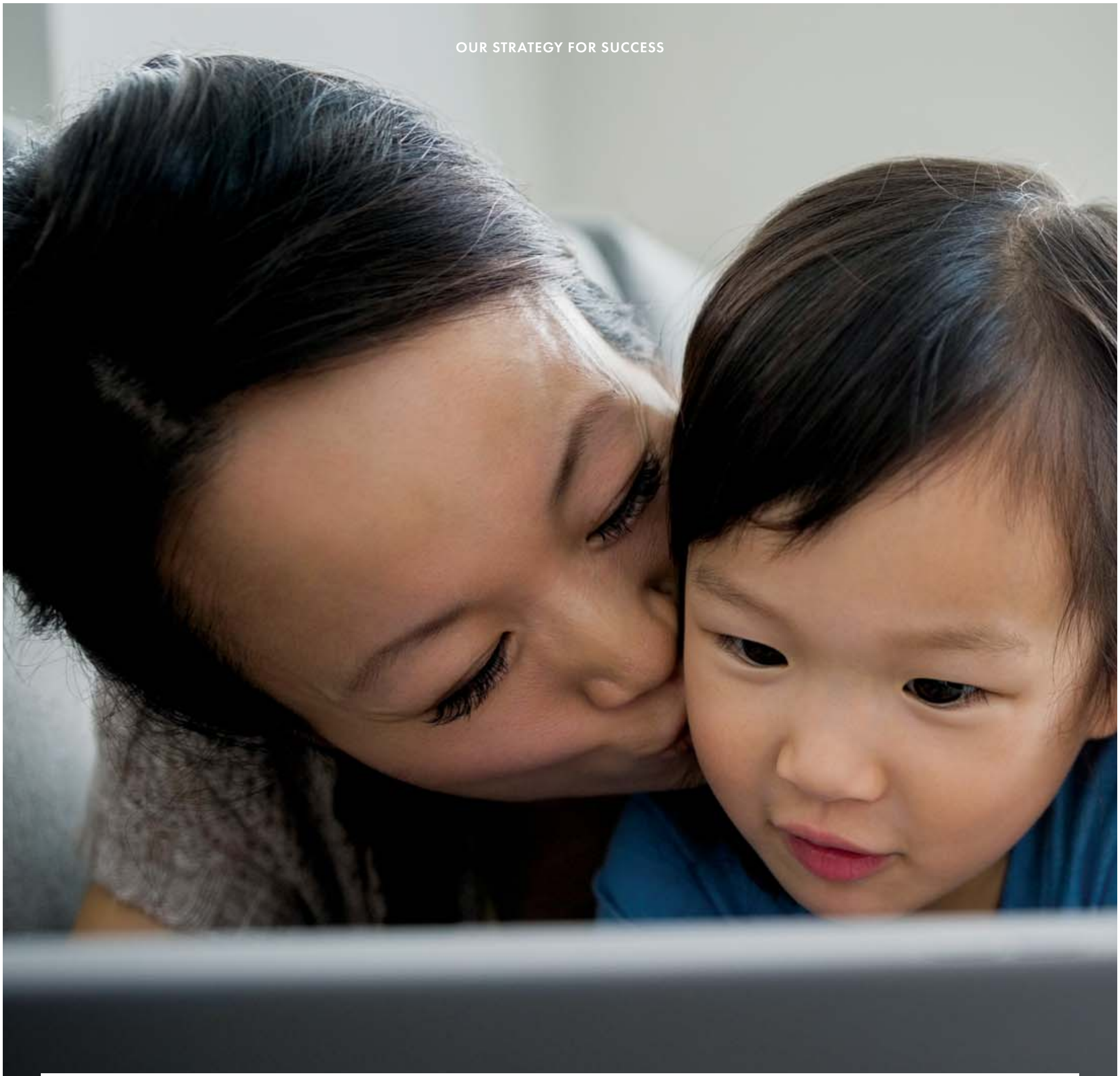


2. DIVERSIFICATION

The electricity industry is transforming from a system based on large centralized generation, transmission and distribution, to small-scale, distributed generation, as a result of declining technology costs and customers' desire for choice in electricity supply. Hydro One's strategy is to adapt our grid investments to reflect this new reality, and to provide the new energy services that customers are demanding.

Hydro One will evaluate new businesses such as providing behind-the-meter products and services that meet requirements for resiliency, reliability, sustainability, quality and security more cost effectively than grid-only supply.

Hydro One will also seek to invest in emerging technology that focuses on innovation in the electricity sector, to identify technologies that could disrupt the Company's business, or that can enhance its business.



3. GROWTH

Through growth, we turn the impossible, possible to reach our goal of becoming the leading North American utility that customers, shareholders and the public can count on. In 2017, we laid the groundwork for future success. We pride ourselves in having a proven record of consolidating electricity utilities.

Avista – In July, we announced our partnership with Avista, where we were acquiring 100 per cent of the shares of Avista, a fully integrated regulated transmission and distribution utility headquartered in Spokane, Washington.

The acquisition, which is expected to close in 2018 following the necessary regulatory approvals, will see Hydro One and Avista create a diversified and growing North American utility leader with tremendous enterprise value.

AVISTA®

BUILDING A SUSTAINABLE FUTURE

"WE ARE COMMITTED TO RUNNING A SUSTAINABLE, SOCIALLY RESPONSIBLE BUSINESS."

MAYO SCHMIDT
PRESIDENT AND CEO

Using Resources Responsibly
Hydro One is committed to building a sustainable future for all Canadians. The sheer scale of our operations — the geographic area we cover, the million of customers we serve and economies we impact — makes it essential that we do our part. We contribute by delivering electricity that is among the cleanest, safest and most reliable in North America.

At a time of growing climate change, Hydro One continues to work to reduce our impact on ecosystems. Internally, our environmental teams collaborate with a range of Hydro One's lines of business to set the agenda, raise awareness and provide guidance on creating real change.

Over the past five years, Hydro One has undergone 103 inspections by the Ministry of the Environment and Climate Change, and by Environment and Climate Change Canada relating to our waste and polychlorinated biphenyls (PCB) storage sites, and environmental compliance approvals. Not a single inspection resulted in a charge. Indeed, we have a strong record in environmental compliance and maintain solid, co-operative relationships with regulators.

Reducing Our Impact
We operate in a highly regulated space, where federal, provincial and municipal bodies require us to assess and mitigate environmental risks. These include everything from the water and emissions we discharge, our land uses, how we dispose of waste and our impact on biodiversity. Permits and approvals are required every step of the way.

To assess, manage and mitigate these risks, Hydro One has an integrated Health, Safety and Environmental Management System (HSEMS), aligned with the ISO 14001 Environmental Management Systems framework. We expect every line of business to identify and reduce high environmental risks in their operations. Since 1999, Hydro One Remote Communities has used an Environmental Management System to reduce their environmental footprint and maintain biodiversity in the environmentally sensitive areas of the province in which they operate.

In 2017, Hydro One Networks Inc. invested $13.9 million in prevention and environmental management, emissions treatment, waste disposal, remediation, water management and environmental approvals.

2017 Achievements
- Developed a sustainability framework, outlining how other initiatives internally support this structure, including our Corporate Social Responsibility Report, HSEMS, other corporate initiatives and our corporate reporting;
- Verification of Hydro One Networks Inc.'s Scope 1 Sulfur Hexafluoride (SF_6) emissions and the verification of Hydro One Remote Communities' greenhouse gas emissions;
- Continued our efforts to further reduce greenhouse gas emissions through better maintenance practices and more efficient tracking;
- Partnered with community groups and non-profits to develop pollinator habitats and other solutions for protecting Ontario's biodiversity;
- Enhanced our Biodiversity GIS (geographic information system) Portal with new source water protection and invasive species layers;
- Developed a Biodiversity Program Framework, outlining the Company's plans for 2018 and beyond with regards to our Biodiversity Program; and
- Installed 12 new osprey nesting boxes for osprey habitats throughout the province.

Community Investment

At Hydro One, we believe in not only powering communities by delivering electricity, but also by investing dollars into the communities where our people and customers live and work.

In 2017, the Community Investment focus was on safety and injury prevention, Science, Technology, Engineering and Math (STEM) education and recreation projects for Indigenous communities. Contributions included a continuing partnership with the Ross Tilley Burn Centre at Sunnybrook Hospital to support the creation of a second burn unit operating room. We also supported the ACT Foundation by empowering Indigenous youth with life-saving skills through CPR and defibrillation training.

$1.1m (approx.)
Donations made to over 40 charitable partners and organizations

$1.3m
Donations made by employees and pensioners to impact local organizations in the communities where they live and work

$1.1m
Community sponsorships made to support local community events

YEAR IN REVIEW

Growth within North America

We announced our plan to acquire Avista to create a top 20 North American utility focused on regulated transmission as well as electricity and natural gas local distribution.

Productivity Savings[1]

$89.5 million in savings in 2017 achieved through operational improvements.

Productivity Savings

Billing

The Company's customer billing accuracy reached an all-time high of 99.3 per cent in 2017.

99.3% BILLING ACCURACY

Leadership

Hydro One was awarded the Progressive Aboriginal Relations Bronze Certification for demonstrating a commitment to Aboriginal communities.

Mayo Schmidt was awarded Ontario Energy Association's 2017 Leader of the Year award.

Renewed Customer Experience

Hydro One introduced a new website in August, making it even easier for customers to do business with us. The website is mobile friendly and promotes more self-service options to meet our changing customer needs.

Launched a new, easy-to-read customer statement. Listening to our customer's feedback to make it simple and straightforward.

Strong North American Reputation

Hydro One demonstrated operational excellence as part of the unprecedented Hurricane Irma restoration efforts in Florida. Hydro One's efforts in Florida earned the Company an award from the Edison Electric Institute.

AWARD WINNING

Customer Service

Customer satisfaction reached the highest it's been in four years for our distribution customers.

Revised customer-focused collection practices have resulted in a $40 million reduction in overdue accounts receivable.

Our System

Distribution

$689 million in distribution assets placed in-service.

Transmission

$889 million in transmission assets placed in-service.

$1,578 MILLION DISTRIBUTION & TRANSMISSION ASSETS PLACED IN-SERVICE

Core Values

At Hydro One, we are led by our purpose to make the impossible, possible for our customers as well as the communities we serve. Our core values guide how all employees behave, how we do our work and how we interact with one another.

Safety Comes First

Nothing is more important than the health and safety of our employees, our customers and the public. We make the world a safer place by setting a high bar that others aspire to.

Stand For People

We foster an open, collaborative work environment. We work to build relationships internally and externally based on trust and mutual respect. We believe in equality for all people and view diversity as a source of our strength.

Empowered to Act

We recognize our power to improve people's lives. We are ready to act in any situation. We capitalize of opportunities. We make the impossible, possible.

Optimism Charges Us

Optimism creates potential in everything we do. We think creatively and innovatively to turn challenges into opportunities.

Win as One

Winning is about doing well while also doing good. It means working together as one Company to deliver strong results for our customers, communities, employees and shareholders.

To learn more about our values, go to:
www.HydroOne.com/investor-relations

1. Productivity savings achieved are as a result of operational improvements in both capital and OM&A.

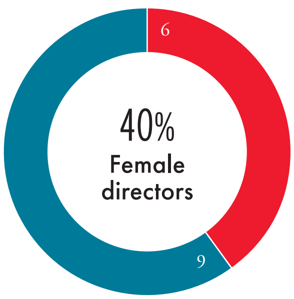
CORPORATE GOVERNANCE OVERVIEW

Board of Directors and Committees

	Audit Committee	Nominating, Corporate Governance Public Policy and Regulatory Committee	Human Resources Committee	Health, Safety, Environment and Indigenous Peoples Committee
David Denison *Chair*				
Mayo Schmidt *President and CEO*				
Ian Bourne		•	★	
Charles Brindamour	•		•	
Marc Caira		•	•	
Christie Clark		•	•	
George Cooke	•			•
Marianne Harris			•	★
Jim Hinds	•			•
Kathryn Jackson		•		•
Roberta Jamieson	•			•
Frances Lankin	•	•		
Philip Orsino	★	•		
Jane Peverett		★	•	
Gale Rubenstein			•	•

★ Chair • Committee Member

Board Diversity



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

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

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

Board Structure

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

To learn more about directors, committee mandates and composition, go to: **www.HydroOne.com/investor-relations**

FINANCIAL REPORT

Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2017 and 2016

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2017. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2017, based on information available to management as of February 12, 2018.

Consolidated Financial Highlights and Statistics

Year ended December 31

(millions of dollars, except as otherwise noted)	2017	2016	Change
Revenues	**5,990**	6,552	(8.6%)
Purchased power	**2,875**	3,427	(16.1%)
Revenues, net of purchased power[1]	**3,115**	3,125	(0.3%)
Operation, maintenance and administration costs	**1,066**	1,069	(0.3%)
Depreciation and amortization	**817**	778	5.0%
Financing charges	**439**	393	11.7%
Income tax expense	**111**	139	(20.1%)
Net income attributable to common shareholders of Hydro One	**658**	**721**	**(8.7%)**
Basic earnings per common share (EPS)	**$ 1.11**	$ 1.21	(8.3%)
Diluted EPS	**$ 1.10**	$ 1.21	(9.1%)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	**$ 1.17**	$ 1.21	(3.3%)
Diluted Adjusted EPS[1]	**$ 1.16**	$ 1.21	(4.1%)
Net cash from operating activities	**1,716**	1,656	3.6%
Funds from operations (FFO)[1]	**1,579**	1,494	5.7%
Capital investments	**1,567**	1,697	(7.7%)
Assets placed in-service	**1,592**	1,605	(0.8%)
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	**52.9%**	52.6%

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

2 Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

Overview

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

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

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	48%	1%

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

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

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

	2017	2016
Electricity transmitted[1] (MWh)	**132,090,992**	136,989,747
Transmission lines spanning the province (circuit-kilometres)	**30,290**	30,259
Rate base (millions of dollars)	**11,251**	10,775
Capital investments (millions of dollars)	**968**	988
Assets placed in-service (millions of dollars)	**889**	937

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

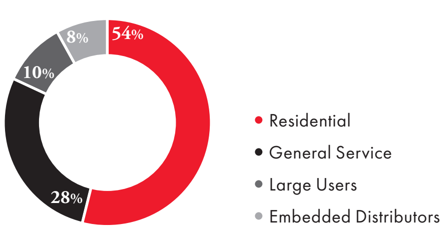
Distribution Segment

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

	2017	2016
Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289
Electricity distributed through Hydro One lines (GWh)[1]	**36,525**	37,394
Distribution lines spanning the province (circuit-kilometres)	**123,361**	122,599
Distribution customers (number of customers)	**1,372,362**	1,355,302
Rate base (millions of dollars)	**7,389**	7,056
Capital investments (millions of dollars)	**588**	703
Assets placed in-service (millions of dollars)	**689**	662

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

2017 Distribution Revenues



Other Business Segment

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

Primary Factors Affecting Results of Operations

Transmission Revenues

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

Distribution Revenues

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

Purchased Power Costs

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

Operation, Maintenance and Administration Costs

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

Depreciation and Amortization

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

Financing Charges

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

Results of Operations

Net Income

Net income attributable to common shareholders for the year ended December 31, 2017 of $658 million is a decrease of $63 million or 8.7% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017–2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;

- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, and a tax recovery of previous year's expenses; as well as reduced vegetation management costs and lower support services costs. These factors were offset by higher consulting costs primarily related to the acquisition of Avista Corporation; and lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system;
- increased financing charges primarily due to the issuance of convertible debentures in August 2017; as well as a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; and
- higher depreciation expense due to an increase in property, plant and equipment.

EPS and Adjusted EPS

EPS of $1.11 in 2017, compared to $1.21 in 2016. The decrease in EPS was driven by lower net income in 2017, as discussed above. Adjusted EPS, which adjusts for costs related to the Avista Corporation acquisition, was $1.17 in 2017, compared to $1.21 in 2016. The decrease in Adjusted EPS was also driven by lower net income in 2017, as discussed above, excluding the aforementioned impact related to Avista Corporation acquisition. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

Year ended December 31

(millions of dollars, except as otherwise noted)	2017	2016	Change
Transmission	**1,578**	1,584	(0.4%)
Distribution	**4,366**	4,915	(11.2%)
Other	**46**	53	(13.2%)
Total revenues	**5,990**	6,552	(8.6%)
Transmission	**1,578**	1,584	(0.4%)
Distribution, net of purchased power	**1,491**	1,488	0.2%
Other	**46**	53	(13.2%)
Total revenues, net of purchased power	**3,115**	3,125	(0.3%)
Transmission: Average monthly Ontario 60-minute peak demand (MW)	**19,587**	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers (GWh)	**25,876**	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017–2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31

(millions of dollars)	2017	2016	Change
Transmission	**375**	382	(1.8%)
Distribution	**593**	608	(2.5%)
Other	**98**	79	24.1%
	1,066	1,069	(0.3%)

Transmission OM&A Costs

The decrease of 1.8% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

Distribution OM&A Costs

The decrease of 2.5% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

Other OM&A Costs

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to the acquisition of Avista Corporation.

Depreciation and Amortization

The increase of $39 million or 5.0% in depreciation and amortization costs for 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The increase of $46 million or 11.7% in financing charges for the year ended December 31, 2017 was primarily due to the following:

- an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense related to the Convertible Debentures issued in August 2017.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $28 million compared to 2016, and the Company realized an effective tax rate of approximately 14.0% in 2017, compared to approximately 15.7% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 9, 2017	March 14, 2017	March 31, 2017	$ 0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$ 0.22	131
August 8, 2017	September 12, 2017	September 29, 2017	$ 0.22	131
November 9, 2017	December 12, 2017	December 29, 2017	$ 0.22	131
				518

Following the conclusion of the fourth quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 12, 2018	March 13, 2018	March 29, 2018	$ 0.22	131

Selected Annual Financial Statistics

Year ended December 31

(millions of dollars, except per share amounts)	2017	2016	2015
Revenues	**5,990**	6,552	6,538
Net income attributable to common shareholders	**658**	721	690
Basic EPS	**$ 1.11**	$ 1.21	$ 1.39
Diluted EPS	**$ 1.10**	$ 1.21	$ 1.39
Basic Adjusted EPS	**$ 1.17**	$ 1.21	$ 1.16
Diluted Adjusted EPS	**$ 1.16**	$ 1.21	$ 1.16
Dividends per common share declared	**$ 0.87**	$ 0.97[1]	$ 1.83
Dividends per preferred share declared	**$ 1.06**	$ 1.12	$ 1.03

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

December 31

(millions of dollars)	2017	2016	2015
Total assets	**25,701**	25,351	24,294
Total non-current financial liabilities	**9,802**	10,078	8,207

Quarterly Results of Operations

Quarter ended

(millions of dollars, except EPS)	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	**1,439**	1,522	1,371	1,658	1,614	1,706	1,546	1,686
Purchased power	**662**	675	649	889	858	870	803	896
Revenues, net of purchased power	**777**	847	722	769	756	836	743	790
Net income to common shareholders	**155**	219	117	167	128	233	152	208
Basic EPS	**$ 0.26**	$ 0.37	$ 0.20	$ 0.28	$ 0.22	$ 0.39	$ 0.26	$ 0.35
Diluted EPS	**$ 0.26**	$ 0.37	$ 0.20	$ 0.28	$ 0.21	$ 0.39	$ 0.25	$ 0.35
Basic Adjusted EPS[1]	**$ 0.29**	$ 0.40	$ 0.20	$ 0.28	$ 0.22	$ 0.39	$ 0.26	$ 0.35
Diluted Adjusted EPS[1]	**$ 0.28**	$ 0.40	$ 0.20	$ 0.28	$ 0.21	$ 0.39	$ 0.25	$ 0.35

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

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

Capital Investments

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

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016	Change
Transmission	**889**	937	(5.1%)
Distribution	**689**	662	4.1%
Other	**14**	6	133.3%
Total assets placed in-Service	**1,592**	1,605	(0.8%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016	Change
Transmission			
Sustaining	**764**	750	1.9%
Development	**137**	156	(12.2%)
Other	**67**	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	**280**	384	(27.1%)
Development	**227**	217	4.6%
Other	**81**	102	(20.6%)
	588	703	(16.4%)
Other	**11**	6	83.3%
Total capital investments	**1,567**	1,697	(7.7%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$ 57 million[1]	$ 52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Expansion Station	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$ 7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$ 1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$ 85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$ 93 million	$ 51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$ 95 million	$ 44 million

1 In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.

2 The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017–2018 transmission rates decision issued in September 2017. The projections and the timing of 2019–2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Other	9	8	6	9	8
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	217	272	184	177	179
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

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

Summary of Sources and Uses of Cash

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

Year ended December 31 (millions of dollars)	2017	2016
Cash provided by operating activities	**1,716**	1,656
Cash provided by (used in) financing activities	**(201)**	161
Cash used in investing activities	**(1,540)**	(1,861)
Decrease in cash and cash equivalents	**(25)**	(44)

Cash Provided by Operating Activities

Cash from Operating Activities increased by $60 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash Provided by Financing Activities

Sources of Cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- In 2017, the Company received proceeds of $513 million, representing the first instalment of the convertible debentures issued, gross of $27 million financing costs, compared to no convertible debentures issuances in 2016.

Uses of Cash

- Dividends paid in 2017 were $536 million, consisting of $518 million common share dividends and $18 million of preferred share dividends, compared to dividends of $596 million paid in 2016, consisting of $577 million common share dividends and $19 million of preferred share dividends. The 2016 common share dividends included $77 million of dividends for the post-IPO period from November 5 to December 31, 2015, and $500 million of dividends for the year ended December 31, 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash Used in Investing Activities

Uses of Cash

- Capital expenditures were $114 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

Liquidity and Financing Strategy

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2017, Hydro One Inc. had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province. See "Other Developments – Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures. The Convertible Debentures instalment receipts trade on the Toronto Stock Exchange under the ticker symbol "H.IR". The Convertible Debentures were sold as part of Hydro One's acquisition financing strategy to acquire Avista Corporation (see section Other Developments – Avista Corporation Purchase agreement), which includes the issuance of $1,540 million of Hydro One common shares and US$2.6 billion of Hydro One debt. The Convertible Debentures were sold to satisfy the equity component of the acquisition financing strategy.

To mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed by the issuance of Convertible Debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. The balance of the Avista Corporation acquisition will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge. At December 31, 2017, a fair value loss of $3 million was recorded with a corresponding derivative liability.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

1 On July 19, 2017, S&P revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

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

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

At December 31, 2017, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
S&P[1]	A-1	A

1 On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

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

Pension Plan

In 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

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

Other Obligations

Off-Balance Sheet Arrangements

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

Summary of Contractual Obligations and Other Commercial Commitments

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

December 31, 2017

(millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations (due by year)					
Long-term debt – principal repayments	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Convertible debentures – principal repayments[1]	513	—	—	—	513
Convertible debentures – interest payments	601	62	123	123	293
Short-term notes payable	926	926	—	—	—
Pension contributions[2]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	44	12	18	10	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	20,512	2,433	2,580	2,073	13,462
Other commercial commitments (by year of expiry)					
Credit facilities[3]	2,550	—	—	2,550	—
Letters of credit[4]	177	177	—	—	—
Guarantees[5]	325	325	—	—	—
Total other commercial commitments	3,052	502	—	2,550	—

1 The Company expects that the Convertible Debentures will be converted to common shares upon closing of the Avista Corporation acquisition.
2 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.
3 In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.
4 Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.
5 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Regulation

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

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

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

1 In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

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

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

1 On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks – Transmission

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

In its 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's 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 Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018–2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. 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. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks – Distribution

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

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

In Hydro One's December 21, 2017 update to the 2018–2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018–2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

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

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018–2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018–2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

Other Developments

Strategy

In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Common Shares

On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly held approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One, representing approximately 2.4% of the outstanding common shares, to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. After completing this transaction, the Province owns approximately 47.4% or 282.4 million common shares of Hydro One. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

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, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Exemptive Relief

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

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is expected to occur in the second half of 2018, subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. On November 21, 2017, the Merger was approved by the shareholders of Avista Corporation. On January 16, 2018, the Federal Energy Regulatory Commission approved the Merger application. Required filings with a number of other agencies will be made in the coming months, including with the Committee on Foreign Investment in the United States, the Federal Communications Commission, and the Department of Justice and the Federal Trade Commission pursuant to the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*.

Convertible Debenture Offering

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company and its wholly-owned subsidiary, 2587264 Ontario Inc., completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures represented by instalment receipts (Debenture Offering). Upon closing of the Avista Corporation transaction and conversion of the Convertible Debentures into Hydro One common shares, the Province's ownership of Hydro One will decrease to approximately 42.3%. See section "Liquidity and Financing Strategy".

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Litigation

Litigation Relating to the Merger

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., 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 plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

Hydro One Work Force

Hydro One has a skilled and flexible work force of approximately 5,400 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2017.

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,362	706	4,068
The Society	1,379	35	1,414
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,741	1,995	6,736
Management and non-represented employees	681	23	704
Total employees	5,422	2,018	7,440

1 Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.
2 The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-Based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 429,980 and 230,600 PSUs, respectively, and 393,430 and 254,150 RSUs, respectively, were outstanding.

Non-GAAP Measures

FFO

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

Year ended December 31 (millions of dollars)	2017	2016
Net cash from operating activities	**1,716**	1,656
Changes in non-cash balances related to operations	**(113)**	(134)
Preferred share dividends	**(18)**	(19)
Distributions to noncontrolling interest	**(6)**	(9)
FFO	**1,579**	1,494

Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs related to the Avista Corporation acquisition from net income. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and provides users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

Year ended December 31	2017	2016
Net income attributable to common shareholders (millions of dollars)	**658**	721
Costs related to acquisition of Avista Corporation (millions of dollars)	**36**	—
Adjusted net income attributable to common shareholders (millions of dollars)	**694**	721
Weighted average number of shares		
Basic	**595,287,586**	595,000,000
Effect of dilutive stock-based compensation plans	**2,234,665**	1,700,823
Diluted	**597,522,251**	596,700,823
Adjusted EPS		
Basic	**$ 1.17**	$ 1.21
Diluted	**$ 1.16**	$ 1.21

Revenues, Net of Purchased Power

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

Year ended December 31 (millions of dollars)	2017	2016
Revenues	**5,990**	6,552
Less: Purchased power	**2,875**	3,427
Revenues, net of purchased power	**3,115**	3,125

Year ended December 31 (millions of dollars)	2017	2016
Distribution revenues	**4,366**	4,915
Less: Purchased power	**2,875**	3,427
Distribution revenues, net of purchased power	**1,491**	1,488

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

Related Party Transactions

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 (millions of dollars)

Related Party	Transaction	2017	2016
Province	Dividends paid	**301**	451
IESO	Power purchased	**1,583**	2,096
	Revenues for transmission services	**1,521**	1,549
	Amounts related to electricity rebates	**357**	—
	Distribution revenues related to rural rate protection	**247**	125
	Distribution revenues related to the supply of electricity to remote northern communities	**32**	32
	Funding received related to CDM programs	**59**	63
OPG	Power purchased	**9**	6
	Revenues related to provision of construction and equipment maintenance services	**3**	5
	Costs related to the purchase of services	**1**	1
OEFC	Power purchased from power contracts administered by the OEFC	**2**	1
OEB	OEB fees	**8**	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	**—**	3

Risk Management and Risk Factors

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications – Hydro One Networks – Transmission"), may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

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

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

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

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

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

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

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

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

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

Risks Relating to Regulatory Treatment of Deferred Tax Asset
As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications – Hydro One Networks – Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

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

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

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

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

Currently, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights.

The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

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

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

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. The Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity.

Risk Associated with Information Technology Infrastructure and Data Security

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

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

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

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with the Society with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020.

Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk
By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

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

Risk Associated with Arranging Debt Financing
The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Corporation to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company. This risk may be further exacerbated by the funding requirements for completing the Merger. See also "Risk Factors Relating to the Merger – Sources of funding that would be used to fund the Merger may not be available"

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

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

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

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

Risks Relating to Asset Condition and Capital Projects
The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However, the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure.

The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

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

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

Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

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

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

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

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

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

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

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

Risk of Recoverability of Total Compensation Costs

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

Other Post-Employment and Post-Retirement Benefits Risks

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

Risk Associated with Outsourcing Arrangements

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

Risk from Provincial Ownership of Transmission Corridors

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

Litigation Risks

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

Transmission Assets on Third-Party Lands Risk

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

Reputational, Public Opinion and Political Risk

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

Risks Associated with Acquisitions

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

Risk Factors Relating to the Merger

Hydro One May Fail to Complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated or at all. The completion of the Merger is subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro

One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US$103 million.

Length of Time Required to Complete the Merger is Unknown
As described above under "Hydro One may fail to complete the Merger", the closing of the Merger is subject to the receipt of certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on Hydro One's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavourable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), Hydro One could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required regulatory approvals and satisfying the other required closing conditions.

Foreign Exchange Risk
The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger. This risk has been partially mitigated through entering into a foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars which is contingent upon the closing of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional Demands Will be Placed on Hydro One as a Result of the Merger
As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of Funding that Would be Used to Fund the Merger May not be Available
Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company. There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates or changes in tax rates that could affect the underlying after-tax cost of any financing may affect the expected accretion of the Merger.

Hydro One Expects to Incur Significant Merger-Related Expenses
Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approvals. Additional unanticipated costs may be incurred.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger
One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. The plaintiffs in the lawsuit are seeking to enjoin the Merger and may pursue other remedies, including monetary damages and attorneys' fees. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One, including by delaying or preventing the Merger from becoming effective. See also "Other Developments – Litigation – Litigation Relating to the Merger".

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will Substantially Increase its Amount of Indebtedness Following the Merger
After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US$1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a pro forma basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (*pro formas* assumed no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One's substantially increased amount of indebtedness following the Merger may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering Could Result in a Downgrade of Hydro One's Credit Ratings
The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering or otherwise could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with the Province

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

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

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

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

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

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

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

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

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

Critical Accounting Estimates and Judgments

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

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

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

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

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

Weighted Average Discount Rate
The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets
The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

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

Rate of Cost of Living Increase
The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2017.

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

Mortality Assumptions
The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

Rate of Increase in Health Care Cost Trends
The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

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

Asset Impairment
Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2017, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting
Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction

of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

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

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of 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 at December 31, 2017.

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

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

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

New Accounting Pronouncements

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

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02 2018-01	February 2016 – January 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 Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
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 has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

Summary of Fourth Quarter Results of Operations

Three months ended December 31

(millions of dollars, except EPS)	2017	2016	Change
Revenues			
Distribution	**1,049**	1,228	(14.6%)
Transmission	**379**	373	1.6%
Other	**11**	13	(15.4%)
	1,439	1,614	(10.8%)
Costs			
Purchased power	**662**	858	(22.8%)
OM&A			
Distribution	**146**	163	(10.4%)
Transmission	**79**	98	(19.4%)
Other	**19**	26	(26.9%)
	244	287	(15.0%)
Depreciation and amortization	**214**	204	4.9%
	1,120	1,349	(17.0%)
Income before financing charges and income taxes	**319**	**265**	**20.4%**
Financing charges	**119**	101	17.8%
Income before income taxes	**200**	**164**	**22.0%**
Income taxes	**38**	29	31.0%
Net income	**162**	135	20.0%
Net income attributable to common shareholders of Hydro One	**155**	**128**	**21.1%**
Basic EPS	**$ 0.26**	$ 0.22	18.2%
Diluted EPS	**$ 0.26**	$ 0.21	23.8%
Basic Adjusted EPS	**$ 0.29**	$ 0.22	31.8%
Diluted Adjusted EPS	**$ 0.28**	$ 0.21	33.3%
Capital Investments			
Distribution	**161**	201	(19.9%)
Transmission	**267**	274	(2.6%)
Other	**3**	2	50.0%
	431	477	(9.6%)
Assets Placed In-Service			
Distribution	**207**	211	(1.9%)
Transmission	**522**	488	7.0%
Other	**4**	0	100.0%
	733	699	4.9%

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2017 of $155 million is an increase of $27 million or 21.1% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017–2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to the issuance of Convertible Debentures in August 2017.

EPS and Adjusted EPS

EPS was $0.26 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in EPS was driven by higher net income for the fourth quarter of 2017, as discussed above. Adjusted EPS, which adjusts for costs related to Avista Corporation acquisition, was $0.29 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in Adjusted EPS was also driven by higher net income for the fourth quarter of 2017, net of aforementioned impact related to Avista Corporation acquisition.

Revenues

The quarterly increase of $6 million or 1.6% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $19 million or 19.4% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations; lower support services costs; and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $17 million or 10.4% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $10 million or 4.9% in depreciation and amortization costs for the fourth quarter of 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The quarterly increase of $18 million or 17.8% in financing charges was primarily due to an increase in interest expense related to the Convertible Debentures issued in August 2017; partially offset by a decrease in interest expense on long-term debt resulting from a decrease in weighted average long-term debt outstanding during the quarter, together with a decrease in the weighted average interest rate.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $9 million compared to 2016, and the Company realized an effective tax rate of approximately 19.0% in the fourth quarter of 2017, compared to approximately 17.7% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

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

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

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

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

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

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by

- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

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

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

Forward-Looking Statements and Information

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion; and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Convertible Debentures; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the appointment of Hydro One's new Chief Financial Officer; risk associated with acquisitions; cyber and data security; expectations related to work force demographics; the Company's financing strategy and foreign currency hedging relating to the acquisition of Avista Corporation; class action litigation, including litigation relating to the Merger; the risk that the Company may fail to complete the Merger; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; the Province's ownership of Hydro One; future sales of shares of Hydro One; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

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

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;

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

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

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

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

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The 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 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 Consolidated Financial Statements. The preparation of the 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. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 12, 2018.

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 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, 2017. 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 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 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 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:

Mayo Schmidt
President and Chief Executive Officer

Christopher Lopez
Senior Vice President, Finance acting in the capacity of Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Hydro One Limited

We have audited the accompanying consolidated financial statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years 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 United States 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 audits. We conducted our audits 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 consolidated 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 in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2017 and December 31, 2016, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

February 12, 2018
Toronto, Canada

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) (Note 27)	**4,366**	4,915
Transmission (includes $1,523 related party revenues; 2016 – $1,553) (Note 27)	**1,578**	1,584
Other	**46**	53
	5,990	6,552
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) (Note 27)	**2,875**	3,427
Operation, maintenance and administration (Note 27)	**1,066**	1,069
Depreciation and amortization (Note 5)	**817**	778
	4,758	5,274
Income before financing charges and income taxes	**1,232**	1,278
Financing charges (Note 6)	**439**	393
Income before income taxes	**793**	885
Income taxes (Note 7)	**111**	139
Net income	**682**	746
Other comprehensive income	**1**	—
Comprehensive income	**683**	746
Net income attributable to:		
Noncontrolling interest (Note 26)	**6**	6
Preferred shareholders	**18**	19
Common shareholders	**658**	721
	682	746
Comprehensive income attributable to:		
Noncontrolling interest (Note 26)	**6**	6
Preferred shareholders	**18**	19
Common shareholders	**659**	721
	683	746
Earnings per common share (Note 24)		
Basic	**$ 1.11**	$ 1.21
Diluted	**$ 1.10**	$ 1.21
Dividends per common share declared (Note 23)	**$ 0.87**	$ 0.97

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31		
(millions of Canadian dollars)	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	**25**	50
Accounts receivable (Note 8)	**636**	838
Due from related parties (Note 27)	**253**	158
Other current assets (Note 9)	**105**	102
	1,019	1,148
Property, plant and equipment (Note 10)	**19,947**	19,140
Other long-term assets:		
Regulatory assets (Note 12)	**3,049**	3,145
Deferred income tax assets (Note 7)	**987**	1,235
Intangible assets (Note 11)	**369**	349
Goodwill (Note 4)	**325**	327
Other assets	**5**	7
	4,735	5,063
Total assets	**25,701**	25,351
Liabilities		
Current liabilities:		
Short-term notes payable (Note 15)	**926**	469
Long-term debt payable within one year (Notes 15, 17)	**752**	602
Accounts payable and other current liabilities (Note 13)	**905**	945
Due to related parties (Note 27)	**157**	147
	2,740	2,163
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) (Notes 15, 17)	**9,315**	10,078
Convertible debentures (Notes 16, 17)	**487**	—
Regulatory liabilities (Note 12)	**128**	209
Deferred income tax liabilities (Note 7)	**71**	60
Other long-term liabilities (Note 14)	**2,707**	2,752
	12,708	13,099
Total liabilities	**15,448**	15,262
Contingencies and Commitments (Notes 29, 30)		
Subsequent Events (Note 32)		
Noncontrolling interest subject to redemption (Note 26)	**22**	22
Equity		
Common shares (Note 22)	**5,631**	5,623
Preferred shares (Note 22)	**418**	418
Additional paid-in capital (Note 25)	**49**	34
Retained earnings	**4,090**	3,950
Accumulated other comprehensive loss	**(7)**	(8)
Hydro One shareholders' equity	**10,181**	10,017
Noncontrolling interest (Note 26)	**50**	50
Total equity	**10,231**	10,067
	25,701	25,351

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31, 2017

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

Year ended December 31, 2016

(millions of Canadian dollars)	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest (Note 26)	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	740	—	740	4	744
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(6)	(6)
Dividends on preferred shares	—	—	—	(19)	—	(19)	—	(19)
Dividends on common shares	—	—	—	(577)	—	(577)	—	(577)
Stock-based compensation (Note 25)	—	—	24	—	—	24	—	24
December 31, 2016	5,623	418	34	3,950	(8)	10,017	50	10,067

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31		
(millions of Canadian dollars)	2017	2016
Operating activities		
Net income	**682**	746
Environmental expenditures	**(24)**	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	**727**	688
Regulatory assets and liabilities	**112**	(16)
Deferred income taxes	**85**	114
Other	**21**	10
Changes in non-cash balances related to operations (Note 28)	**113**	134
Net cash from operating activities	**1,716**	1,656
Financing activities		
Long-term debt issued	**—**	2,300
Long-term debt repaid	**(602)**	(502)
Short-term notes issued	**3,795**	3,031
Short-term notes repaid	**(3,338)**	(4,053)
Convertible debentures issued (Note 16)	**513**	—
Dividends paid	**(536)**	(596)
Distributions paid to noncontrolling interest	**(6)**	(9)
Other (Note 16)	**(27)**	(10)
Net cash from (used in) financing activities	**(201)**	161
Investing activities		
Capital expenditures (Note 28)		
Property, plant and equipment	**(1,467)**	(1,600)
Intangible assets	**(80)**	(61)
Acquisitions (Note 4)	**—**	(224)
Capital contributions received (Note 28)	**9**	21
Other	**(2)**	3
Net cash used in investing activities	**(1,540)**	(1,861)
Net change in cash and cash equivalents	**(25)**	(44)
Cash and cash equivalents, beginning of year	**50**	94
Cash and cash equivalents, end of year	**25**	50

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

1. Description of the Business

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2017, the Province held approximately 47.4% (2016 – 70.1%) of the common shares of Hydro One.

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

2. Significant Accounting Policies

Basis of Consolidation

These 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 United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and its 66% interest in B2M Limited Partnership (B2M LP).

The Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

Transmission

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 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 January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Distribution

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

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 in the period that the assessment is made.

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

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is 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.

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

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

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

Noncontrolling Interest

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

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

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return 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 liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, 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.

The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

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, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2017 and 2016, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2017 or 2016.

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 exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation 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 projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. 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 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 costs in the Consolidated Statements of Operations and Comprehensive Income.

Defined Benefit Pension

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

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 future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

Share Grant Plans
Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans
The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Long-Term Incentive Plan (LTIP)
The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under its LTIP, at fair value based on the grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation 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 equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. 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.

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. 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

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02 2018-01	February 2016 – January 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 Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
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 has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. Business Combinations

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions. See Note 16 – Convertible Debentures and Note 17 – Fair Value of Financial Instruments and Risk Management for details of convertible debentures and foreign exchange contract, respectively, related to financing of the Merger.

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 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. The acquisition is subject to regulatory approval by the OEB.

5. Depreciation and Amortization

Year ended December 31

(millions of dollars)	2017	2016
Depreciation of property, plant and equipment	**641**	612
Asset removal costs	**90**	90
Amortization of intangible assets	**62**	56
Amortization of regulatory assets	**24**	20
	817	778

6. Financing Charges

Year ended December 31

(millions of dollars)	2017	2016
Interest on long-term debt	**450**	424
Interest on convertible debentures	**24**	—
Interest on short-term notes	**6**	9
Unrealized loss on foreign exchange contract	**3**	—
Other	**14**	16
Less: Interest capitalized on construction and development in progress	**(56)**	(54)
Interest earned on cash and cash equivalents	**(2)**	(2)
	439	393

7. Income Taxes

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)	2017	2016
Income before income taxes	**793**	885
Income taxes at statutory rate of 26.5% (2016 – 26.5%)	**210**	235
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	**(55)**	(53)
Pension contributions in excess of pension expense	**(13)**	(16)
Overheads capitalized for accounting but deducted for tax purposes	**(17)**	(16)
Interest capitalized for accounting but deducted for tax purposes	**(15)**	(14)
Environmental expenditures	**(6)**	(5)
Other	**3**	5
Net temporary differences	**(103)**	(99)
Net permanent differences	**4**	3
Total income taxes	**111**	139

The major components of income tax expense are as follows:

Year ended December 31

(millions of dollars)	2017	2016
Current income taxes	**26**	25
Deferred income taxes	**85**	114
Total income taxes	**111**	139
Effective income tax rate	**14.0%**	15.7%

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, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	**125**	495
Non-depreciable capital property	**271**	271
Post-retirement and post-employment benefits expense in excess of cash payments	**561**	607
Environmental expenditures	**71**	74
Non-capital losses and tax credit carryforward	**255**	213
Tax credit carryforwards	**49**	27
Investment in subsidiaries	**84**	75
Other	**13**	3
	1,429	1,765
Less: valuation allowance	**(364)**	(352)
Total deferred income tax assets	**1,065**	1,413
Less: current portion	**—**	—
	1,065	1,413
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	**(47)**	(153)
Goodwill	**(10)**	(10)
Capital cost allowance in excess of depreciation and amortization	**(75)**	(64)
Other	**(17)**	(11)
Total deferred income tax liabilities	**(149)**	(238)
Less: current portion	**—**	—
	(149)	(238)
Net deferred income tax assets	**916**	1,175

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 (millions of dollars)	2017	2016
Long-term:		
Deferred income tax assets	**987**	1,235
Deferred income tax liabilities	**(71)**	(60)
Net deferred income tax assets	**916**	1,175

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 – $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, 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)	2017	2016
2034	**2**	2
2035	**222**	222
2036	**560**	580
2037	**175**	—
Total losses	**959**	804

8. Accounts Receivable

December 31

(millions of dollars)	2017	2016
Accounts receivable – billed	**298**	431
Accounts receivable – unbilled	**367**	442
Accounts receivable, gross	**665**	873
Allowance for doubtful accounts	**(29)**	(35)
Accounts receivable, net	**636**	838

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31

(millions of dollars)	2017	2016
Allowance for doubtful accounts – beginning	**(35)**	(61)
Write-offs	**25**	37
Additions to allowance for doubtful accounts	**(19)**	(11)
Allowance for doubtful accounts – ending	**(29)**	(35)

9. Other Current Assets

December 31

(millions of dollars)	2017	2016
Regulatory assets (Note 12)	**46**	37
Materials and supplies	**18**	19
Prepaid expenses and other assets	**41**	46
	105	102

10. Property, Plant and Equipment

December 31, 2017

(millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	**15,509**	**5,162**	**989**	**11,336**
Distribution	**10,213**	**3,513**	**149**	**6,849**
Communication	**1,266**	**853**	**31**	**444**
Administration and service	**1,561**	**857**	**46**	**750**
Easements	**638**	**70**	**—**	**568**
	29,187	**10,455**	**1,215**	**19,947**

December 31, 2016

(millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,233	777	20	476
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,841	9,935	1,234	19,140

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 – $52 million).

11. Intangible Assets

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**

December 31, 2016

(millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 – $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 – $67 million; 2019 – $57 million; 2020 – $40 million; 2021 – $39 million; and 2022 – $36 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)	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	**1,762**	1,587
Pension benefit regulatory asset	**981**	900
Post-retirement and post-employment benefits	**36**	243
Environmental	**196**	204
Share-based compensation	**40**	31
Debt premium	**27**	32
Foregone revenue deferral	**23**	—
Distribution system code exemption	**10**	10
B2M LP start-up costs	**4**	5
Retail settlement variance account	—	145
2015–2017 rate rider	—	7
Pension cost variance	—	4
Other	**16**	14
Total regulatory assets	**3,095**	3,182
Less: current portion	**(46)**	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	**60**	69
External revenue variance	**46**	64
CDM deferral variance	**28**	54
Pension cost variance	**23**	—
2015–2017 rate rider	**6**	—
Deferred income tax regulatory liability	**5**	4
Other	**17**	18
Total regulatory liabilities	**185**	209
Less: current portion	**(57)**	—
	128	209

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 2017 income tax expense would have been higher by approximately $113 million (2016 – $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its 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's 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 Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. 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. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

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 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. In the absence of rate-regulated accounting, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 – OCI higher by $52 million).

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 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. In the absence of rate-regulated accounting, 2017 OCI would have been higher by $207 million (2016 – lower by $3 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2017, the environmental regulatory asset increased by $1 million (2016 – decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 – $10 million) due to changes in the land assessment and remediation liability. 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, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 – $20 million), and 2017 financing charges would have been higher by $8 million (2016 – $8 million).

Share-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, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 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.

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.

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 will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

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 March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. 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.

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. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015–2017 Rate Rider.

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.

Pension Cost Variance

A pension cost variance 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. The balance in this regulatory account reflects the deficit of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which was recovered through the 2015–2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 – $25 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.

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. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

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 Conservation and Demand Management (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 relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. Accounts Payable and Other Current Liabilities

December 31

(millions of dollars)	2017	2016
Accounts payable	**177**	181
Accrued liabilities	**572**	659
Accrued interest	**99**	105
Regulatory liabilities (Note 12)	**57**	—
	905	945

14. Other Long-Term Liabilities

December 31

(millions of dollars)	2017	2016
Post-retirement and post-employment benefit liability (Note 19)	**1,519**	1,641
Pension benefit liability (Note 19)	**981**	900
Environmental liabilities (Note 20)	**168**	177
Asset retirement obligations (Note 21)	**9**	9
Long-term accounts payable and other liabilities	**30**	25
	2,707	2,752

15. Debt and Credit Agreements

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At December 31, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

(millions of dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2022[1]	2,300
Hydro One		
Five-year senior, revolving term credit facility	November 2021	250
Total		2,550

1 In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

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, 2017 and 2016:

December 31 (millions of dollars)	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	**750**	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
3.20% Series 25 notes due 2022	**600**	600
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
4.00% Series 24 notes due 2051	**225**	225
3.79% Series 26 notes due 2062	**310**	310
4.29% Series 30 notes due 2064	**50**	50
Hydro One Inc. long-term debt (a)	**9,923**	10,523
6.6% Senior Secured Bonds due 2023 (Face value – $110 million)	**136**	144
4.6% Note Payable due 2023 (Face value – $36 million)	**40**	40
HOSSM long-term debt (b)	**176**	184
	10,099	10,707
Add: Net unamortized debt premiums	**14**	15
Add: Unrealized mark-to-market gain[2]	**(9)**	(2)
Less: Deferred debt issuance costs	**(37)**	(40)
Total long-term debt	**10,067**	10,680

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 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. Long-Term Debt

At December 31, 2017, long-term debt of $9,923 million (2016 – $10,523 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 – $2,300 million issued and $500 million repaid).

(b) HOSSM Long-Term Debt

At December 31, 2017, long-term debt of $176 million (2016 – $184 million), with a face value of $146 million (2016 – $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 – $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 (millions of dollars)	2017	2016
Current liabilities:		
Long-term debt payable within one year	**752**	602
Long-term liabilities:		
Long-term debt	**9,315**	10,078
Total long-term debt	**10,067**	10,680

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments (millions of dollars)	Weighted Average Interest Rate (%)
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments (millions of dollars)
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023–2027	1,672
2028+	4,081
	7,690

16. Convertible Debentures

(millions of dollars, except as otherwise noted)	
Maturity date	September 30, 2027
Coupon rate	4.00%
Conversion price per common share	$ 21.40
Carrying value at December 31, 2016	—
Receipt of Initial Instalment, net of deferred financing costs	486
Amortization of deferred financing costs	1
Carrying value at December 31, 2017	487
Face value at December 31, 2017	513

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) is payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred financing costs of $27 million, which are being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures will mature on September 30, 2027. A coupon rate of 4% is paid on the $1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translates into an effective annual yield of 12%. After the Final Instalment Date, the interest rate will be 0%. The interest expense recorded in 2017 is $24 million.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of the Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date (Make-Whole Payment). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

At the option of the holders and provided that payment of the Final Instalment has been made, each Convertible Debenture will be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures. The conversion feature meets the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized. Between the time the contingency is resolved and the Final Instalment Date, the Company will recognize approximately $92 million of interest expense associated with amortization of the BCF.

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that the Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Avista Corporation will not be satisfied; (ii) termination of the acquisition agreement; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders on or before April 30, 2019. Upon any such redemption, the Company will pay for each Convertible Debenture (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the selling debentureholder on behalf of the holder of the instalment receipt in satisfaction of the final instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in common shares, which will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

17. Fair Value of Financial Instruments and Risk Management

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2017 and 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2017 and 2016 are as follows:

December 31

(millions of dollars)	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$50 million of MTN Series 33 notes	**49**	**49**	50	50
$500 million MTN Series 37 notes	**492**	**492**	498	498
Other notes and debentures	**9,526**	**11,027**	10,132	11,462
Long-term debt, including current portion	**10,067**	**11,568**	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- 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.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition (see Note 4 – Business Combinations) and is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 – Convertible Debentures). If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. This contract is an economic hedge and does not qualify for hedge accounting. It has been accounted for as an undesignated contract.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017

(millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	**25**	**25**	**25**	—	—
	25	**25**	**25**	—	—
Liabilities:					
Short-term notes payable	**926**	**926**	**926**	—	—
Long-term debt, including current portion	**10,067**	**11,568**	—	**11,568**	—
Convertible debentures	**487**	**574**	**574**	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	**9**	**9**	**9**	—	—
Foreign exchange contract	**3**	**3**	—	—	**3**
	11,492	**13,080**	**1,509**	**11,568**	**3**

December 31, 2016

(millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on December 29, 2017 (last business day in December 2017), as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves,probability of closing the Avista Corporation acquisition, and the contract settlement of date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probability of closing the Avista Corporation acquisition and the contract settlement date.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016.

Year ended December 31

(millions of dollars)	**2017**	2016
Fair value, beginning of year	**—**	—
Unrealized loss on foreign exchange contract included in financing charges (Note 6)	**3**	—
Fair value, end of year	**3**	—

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2017 and 2016.

The Company is exposed to foreign exchange fluctuations as a result of entering into a deal-contingent foreign exchange forward agreement (see section Fair Value Measurements of Derivative Instruments above). This agreement is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 – Convertible Debentures).

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, 2017 and 2016 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, 2017 and 2016, 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, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) 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, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, 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 liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

18. Capital Management

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 (millions of dollars)	2017	2016
Long-term debt payable within one year	**752**	602
Short-term notes payable	**926**	469
Less: cash and cash equivalents	**(25)**	(50)
	1,653	1,021
Long-term debt	**9,315**	10,078
Convertible debentures	**487**	—
Preferred shares	**418**	418
Common shares	**5,631**	5,623
Retained earnings	**4,090**	3,950
Total capital	**21,594**	21,090

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. Hydro One Inc.'s 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, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

19. Pension and Post-Retirement and Post-Employment Benefits

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (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.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 – less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 – less than $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 Energy Professionals (The 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 valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 – $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 – based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. 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 but for 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.

Year ended December 31

(millions of dollars)	Pension Benefits 2017	2016	Post-Retirement and Post-Employment Benefits 2017	2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**7,774**	7,683	**1,690**	1,610
Current service cost	**147**	144	**49**	42
Employee contributions	**49**	45	**67**	—
Interest cost	**304**	308	**—**	67
Benefits paid	**(368)**	(354)	**(44)**	(43)
Net actuarial loss (gain)	**352**	(52)	**(197)**	14
Projected benefit obligation, end of year	**8,258**	7,774	**1,565**	1,690
Change in plan assets				
Fair value of plan assets, beginning of year	**6,874**	6,731	**—**	—
Actual return on plan assets	**662**	370	**—**	—
Benefits paid	**(368)**	(354)	**(34)**	(43)
Employer contributions	**87**	108	**34**	43
Employee contributions	**49**	45	**—**	—
Administrative expenses	**(27)**	(26)	**—**	—
Fair value of plan assets, end of year	**7,277**	6,874	**—**	—
Unfunded status	**981**	900	**1,565**	1,690

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31

(millions of dollars)	Pension Benefits 2017	2016	Post-Retirement and Post-Employment Benefits 2017	2016
Other assets[1]	**1**	1	**—**	—
Accrued liabilities	**—**	—	**53**	56
Pension benefit liability	**981**	900	**—**	—
Post-retirement and post-employment benefit liability[2]	**—**	—	**1,519**	1,641
Net unfunded status	**980**	899	**1,572**	1,697

1 Represents the funded status of HOSSM defined benefit pension plan.
2 Includes $7 million (2016 – $7 million) relating to HOSSM post-employment benefit plans.

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations 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 projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31

(millions of dollars)	2017	2016
PBO	**8,258**	7,774
ABO	**7,614**	7,094
Fair value of plan assets	**7,277**	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 – 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 – 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, 2017 and 2016 for the Pension Plan:

Year ended December 31 (millions of dollars)	2017	2016
Current service cost	**147**	144
Interest cost	**304**	308
Expected return on plan assets, net of expenses	**(442)**	(432)
Amortization of actuarial losses	**79**	96
Net periodic benefit costs	**88**	116
Charged to results of operations[1]	**39**	48

1 The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $87 million (2016 – $108 million) were attributed to labour, of which $39 million (2016 – $48 million) was charged to operations, and $48 million (2016 – $60 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, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of dollars)	2017	2016
Current service cost	**49**	42
Interest cost	**67**	67
Amortization of actuarial losses	**16**	15
Net periodic benefit costs	**132**	124
Charged to results of operations	**59**	55

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, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	**3.40%**	3.90%	**3.40%**	3.90%
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%**	4.36%

1 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 – 6.25% in 2017, grading down to 4.36% 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, 2017 and 2016. 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	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.50%**	6.50%
Weighted average discount rate	**3.90%**	4.00%
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	**3.90%**	4.10%
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)	**15.2**	15.3
Rate of increase in health care cost trends[1]	**4.36%**	4.36%

1 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 – 6.38% in 2016, 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 projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2017 and 2016 is as follows:

December 31 (millions of dollars)	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**250**	289
Effect of a 1% decrease in health care cost trends	**(189)**	(221)

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, 2017 and 2016 is as follows:

Year ended December 31 (millions of dollars)	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**29**	23
Effect of a 1% decrease in health care cost trends	**(20)**	(17)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2017 and 2016:

December 31, 2017 Life expectancy at 65 for a member currently at				December 31, 2016 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	**24**	**23**	**24**	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,866	312
Total estimated future benefit payments through to 2027	3,597	590

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)	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	**159**	35
Amortization of actuarial losses	**(79)**	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	**(197)**	14
Amortization of actuarial losses	**(16)**	(15)
Amounts not subject to regulatory treatment	**6**	4
	(207)	(3)

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, 2017 and 2016:

Year ended December 31 (millions of dollars)	2017	2016
Pension Benefits:		
Actuarial loss	**981**	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	**36**	243

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:

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of dollars)	2017	2016	2017	2016
Actuarial loss	**84**	79	**2**	6

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, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

1 Other investments include real estate and infrastructure investments.

At December 31, 2017, the Pension Plan held $11 million (2016 – $11 million) Hydro One corporate bonds and $415 million (2016 – $450 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2017 and 2016. 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, 2017 and 2016, 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 measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016:

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.

December 31, 2016 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares – Canadian	911	—	—	911
Corporate shares – Foreign	2,985	113	—	3,098
Bonds and debentures – Canadian	—	1,943	—	1,943
Bonds and debentures – Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

1 At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 17 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3
The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016.

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 may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of dollars)	2017	2016
Fair value, beginning of year	**425**	301
Realized and unrealized gains	**(31)**	23
Purchases	**171**	151
Sales and disbursements	**(16)**	(50)
Fair value, end of year	**549**	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

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 most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. 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. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

20. Environmental Liabilities

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017

(millions of dollars)	PCB	Land Assessment and Remediation	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**

Year ended December 31, 2016

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Environmental liabilities – beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities – ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

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, 2017

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	**142**	**64**	**206**
Less: discounting environmental liabilities to present value	**(8)**	**(2)**	**(10)**
Discounted environmental liabilities	**134**	**62**	**196**

Year ended December 31, 2016

(millions of dollars)	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

Hydro One records a liability for the estimated future expenditures for land assessment and remediation 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 $142 million (2016 – $158 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 Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 – reduce by $1 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $64 million (2016 – $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 – $10 million).

21. Asset Retirement Obligations

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, 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.

At December 31, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 – $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

22. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 595,386,711 (2016 – 595,000,000) common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

The following tables present the changes to common shares during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017

(number of shares)	Ownership by Public	Ownership by Province	Total
Common shares – beginning	**178,196,340**	**416,803,660**	**595,000,000**
Secondary offering[1]	**120,000,000**	**(120,000,000)**	**—**
Common shares issued – share grants[2]	**371,611**	**—**	**371,611**
Common shares issued – LTIP[3]	**15,100**	**—**	**15,100**
Sale of common shares[4]	**14,391,012**	**(14,391,012)**	**—**
Common shares – ending	**312,974,063**	**282,412,648**	**595,386,711**
	52.6%	**47.4%**	**100%**

1 On May 17, 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.
2 On April 1, 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the Power Workers' Union (PWU) Share Grant Plan.
3 In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.
4 On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Year ended December 31, 2016

(number of shares)	Ownership by Public	Ownership by Province	Total
Common shares – beginning	94,896,340	500,103,660	595,000,000
Secondary offering[1]	83,300,000	(83,300,000)	—
Common shares – ending	178,196,340	416,803,660	595,000,000
	29.9%	70.1%	100%

1 On April 14, 2016, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 72,434,800 common shares of Hydro One on the Toronto Stock Exchange. In addition, the Province granted the underwriters an over-allotment option to purchase up to an additional 10,865,200 common shares of Hydro One which was fully exercised and closed on April 29, 2016. Hydro One did not receive any of the proceeds from the sale of common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2017 and 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2017 and 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2017, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

23. Dividends

In 2017, preferred share dividends in the amount of $18 million (2016 – $19 million) and common share dividends in the amount of $518 million (2016 – $577 million) were declared. The 2016 common share dividends include $77 million for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

24. Earnings Per Common Share

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the LTIP, which are calculated using the treasury stock method.

Year ended December 31	2017	2016
Net income attributable to common shareholders (millions of dollars)	**658**	721
Weighted average number of shares		
Basic	**595,287,586**	595,000,000
Effect of dilutive stock-based compensation plans	**2,234,665**	1,700,823
Diluted	**597,522,251**	596,700,823
EPS		
Basic	**$ 1.11**	$ 1.21
Diluted	**$ 1.10**	$ 1.21

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS until conditions for closing the Avista Corporation acquisition are met.

25. Stock-Based Compensation

Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2017, 371,611 common shares were granted under the Share Grant Plans (2016 – nil). Total share based compensation recognized during 2017 was $17 million (2016 – $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	**5,334,415**	**$ 20.50**
Vested and issued[1]	**(371,611)**	**—**
Forfeited	**(137,072)**	**$ 20.50**
Share grants outstanding – ending	**4,825,732**	**$ 20.50**

1 On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	5,412,354	$ 20.50
Forfeited	(77,939)	$ 20.50
Share grants outstanding – ending	5,334,415	$ 20.50

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 (number of DSUs)	2017	2016
DSUs outstanding – beginning	**99,083**	20,525
DSUs granted	**88,007**	78,558
DSUs outstanding – ending	**187,090**	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 – $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 – $2 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 (number of DSUs)	2017	2016
DSUs outstanding – beginning	**—**	—
Granted	**68,897**	—
Paid	**(1,068)**	—
DSUs outstanding – ending	**67,829**	—

For the year ended December 31, 2017, an expense of $2 million (2016 – $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 – $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 – $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for verall business performance.

During 2017 and 2016, the Company granted awards under its LTIP as follows:

Year ended December 31	PSUs		RSUs	
(number of units)	2017	2016	2017	2016
Units outstanding – beginning	**230,600**	—	**254,150**	—
Units granted	**303,240**	235,420	**242,860**	258,970
Units vested	**(609)**	—	**(14,079)**	—
Units forfeited	**(103,251)**	(4,820)	**(89,501)**	(4,820)
Units outstanding – ending	**429,980**	230,600	**393,430**	254,150

The grant date total fair value of the awards granted in 2017 was $13 million (2016 – $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 – $3 million).

26. Noncontrolling Interest

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (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, 2017 and 2016:

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**

Year ended December 31, 2016

(millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

27. Related Party Transactions

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31

(millions of dollars) Related Party	Transaction	2017	2016
Province	Dividends paid	**301**	451
IESO	Power purchased	**1,583**	2,096
	Revenues for transmission services	**1,521**	1,549
	Amounts related to electricity rebates	**357**	—
	Distribution revenues related to rural rate protection	**247**	125
	Distribution revenues related to the supply of electricity to remote northern communities	**32**	32
	Funding received related to CDM programs	**59**	63
OPG	Power purchased	**9**	6
	Revenues related to provision of construction and equipment maintenance services	**3**	5
	Costs expensed related to the purchase of services	**1**	1
OEFC	Power purchased from power contracts administered by the OEFC	**2**	1
OEB	OEB fees	**8**	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	**—**	3

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

28. Consolidated Statements of Cash Flows

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2017	2016
Accounts receivable	**195**	(60)
Due from related parties	**(95)**	33
Materials and supplies	**1**	2
Prepaid expenses and other assets	**7**	(15)
Accounts payable	**7**	19
Accrued liabilities	**(89)**	53
Due to related parties	**10**	9
Accrued interest	**(6)**	9
Long-term accounts payable and other liabilities	**(2)**	6
Post-retirement and post-employment benefit liability	**85**	78
	113	134

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 (millions of dollars)	2017	2016
Capital investments in property, plant and equipment	**(1,493)**	(1,630)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	**26**	30
Cash outflow for capital expenditures – property, plant and equipment	**(1,467)**	(1,600)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 (millions of dollars)	2017	2016
Capital investments in intangible assets	**(74)**	(67)
Net change in accruals included in capital investments in intangible assets	**(6)**	6
Cash outflow for capital expenditures – intangible assets	**(80)**	(61)

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 2017, capital contributions from these reassessments totalled $9 million (2016 – $21 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)	2017	2016
Net interest paid	**475**	418
Income taxes paid	**12**	32

29. Contingencies

Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One Limited, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One Limited publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One Limited, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

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 2017, the Company paid approximately $2 million (2016 – $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

30. Commitments

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

December 31, 2017

(millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	**139**	**95**	**2**	**2**	**2**	**7**
Long-term software/meter agreement	**17**	**17**	**16**	**2**	**1**	**3**
Operating lease commitments	**12**	**7**	**11**	**6**	**4**	**4**

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 2018.

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.

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, 2017, the Company made lease payments totalling $12 million (2016 – $11 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, 2017

(millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	**250**	**2,300**	—
Letters of credit[1]	**177**	—	—	—	—	—
Guarantees[2]	**325**	—	—	—	—	—

1 Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.
2 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

31. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2017

(millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	**1,578**	**4,366**	**46**	**5,990**
Purchased power	—	**2,875**	—	**2,875**
Operation, maintenance and administration	**375**	**593**	**98**	**1,066**
Depreciation and amortization	**420**	**390**	**7**	**817**
Income (loss) before financing charges and income taxes	**783**	**508**	**(59)**	**1,232**
Capital investments	**968**	**588**	**11**	**1,567**

Year ended December 31, 2016

(millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	1,584	4,915	53	6,552
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	382	608	79	1,069
Depreciation and amortization	390	379	9	778
Income (loss) before financing charges and income taxes	812	501	(35)	1,278
Capital investments	988	703	6	1,697

Total Assets by Segment:

December 31

(millions of dollars)	2017	2016
Transmission	**13,608**	13,071
Distribution	**9,259**	9,379
Other	**2,834**	2,901
Total assets	**25,701**	25,351

Total Goodwill by Segment:

December 31

(millions of dollars)	2017	2016
Transmission (Note 4)	**157**	159
Distribution	**168**	168
Total goodwill	**325**	327

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

32. Subsequent Events

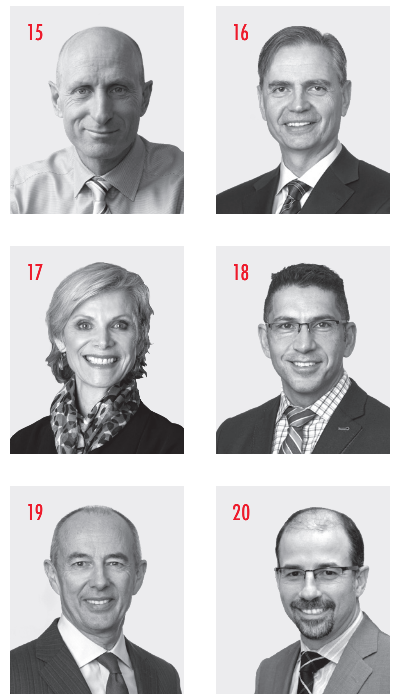
Dividends

On February 12, 2018, preferred share dividends in the amount of $4 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

BOARD OF DIRECTORS & SENIOR LEADERSHIP TEAM

Board of Directors

Senior Leadership Team



For detailed biographical information of Hydro One Limited board members and senior leadership, go to **www.HydroOne.com/Investors**

1. **David Denison,** O.C., FCPA, FCA
   Chair of the Board
2. **Ian Bourne,** ICD.D, F.ICD
   Board Chair, Ballard Power Systems
3. **Charles Brindamour**
   CEO, Intact Financial Corporation
4. **Marcello (Marc) Caira**
   Vice Chair, Restaurants Brands International
5. **Christie Clark,** FCA, FCPA
   Director, Loblaw Companies
6. **George Cooke**
   Board Chair, OMERS Administration Corp
7. **Margaret (Marianne) Harris**
   Board Chair, IIROC
8. **James Hinds**
   Former Board Chair, IESO and OPA
9. **Kathryn J. Jackson,** PH.D
   Director, Portland General Electric
10. **Roberta Jamieson** O.C., C.M., I.P.C, LL.B, LL.D (HON)
    President and CEO, Indspires
11. **Hon. Frances L. Lankin,** O.C., P.C., C.M.
    Member of Senate of Canada
12. **Philip S. Orsino,** O.C., FCA, FCPA
    Director, Bank of Montreal
13. **Jane Peverett,** FCMA, ICD.D
    Director, Canadian Imperial Bank of Commerce
14. **Gale Rubenstein**
    Partner, Goodmans LLP
15. **Mayo Schmidt**
    President and CEO, Hydro One Limited

15. **Mayo Schmidt**
    President and CEO
16. **Greg Kiraly**
    Chief Operating Officer
17. **Judy McKellar**
    EVP, Chief Human Resources Officer
18. **Ferio Pugliese**
    EVP, Customer Care & Corporate Affairs
19. **James (Jamie) Scarlett**
    EVP, Chief Legal Officer
20. **Chris Lopez**
    Senior Vice President, Finance

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483 Bay Street, South Tower
Toronto, ON M5G 2P5
1.416.345.5000
www.HydroOne.com

Customer Inquiries

Customer Service:
1.888.664.9376 or
CustomerCommunications@HydroOne.com

Report an Emergency (24 hours):
1.800.434.1235

Shareholder Services
If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:

Computershare Trust Company of Canada
100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1
1.514.982.7555 or 1.800.564.6253
service@computershare.com

Institutional Investors and Analysts
Institutional investors, securities analysts and others requiring additional financial information can visit www.HydroOne.com/Investors or contact us at:

1.416.345.6867
Investor.Relations@HydroOne.com or
Omar.Javed@HydroOne.com

Media Inquiries
1.416.345.6868 or 1.877.506.7584
Media.Relations@HydroOne.com

Sustainability
Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impactson both. To learn more, visit www.HydroOne.com/OurCommitment

Stock Exchange Listing
Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

Independent Auditors
KPMG LLP

Equity Index Inclusions
Dow Jones Select Utilities (Canada) Index
FTSE All-World Index Series
MSCI World (Canada) Index
S&P/TSX Composite Index
S&P/TSX Utilities Index
S&P/TSX Composite Dividend Index
S&P/TSX Composite Low Volatility Index
S&P/TSX Composite High Dividend Index

Debt Securities
For details of the public debt securities of Hydro One and its subsidiaries, please refer to the "Debt Information" section under www.HydroOne.com/Investors

Online Information
Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of www.HydroOne.com/investor-relations where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, corporate social responsibility and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

Common Share Dividend Information

*2018 Expected Dividend Dates**

Record Date	Payment Date
March 13, 2018	March 29, 2018
June 12, 2018	June 29, 2018
September 11, 2018	September 28, 2018
December 11, 2018	December 31, 2018

*Subject to Board approval

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

Dividend Reinvestment Plan (DRIP)
Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit www.HydroOne.com/DRIP or Computershare Trust Company of Canada at www.InvestorCentre.com/HydroOne

Regulatory Stakeholders

Hydro One is committed to understanding the interests of maintaining and enhancing long-term relationships with its regulatory stakeholders.

Provincial Government,
Ministry of Energy
Policy, legislation, regulations

Ontario Energy Board (OEB)
Independent electric utility price and service quality regulation

Independent Electricity System Operator
Wholesale power market rules, intermediary, North American reliability standards

National Energy Board
Federal regulator, international power lines and substations

North American Electric Reliability Corporation
Continent-wide bulk power reliability standards, certification, monitoring

For more information, visit:
www.HydroOne.com/regulatory

Design: Craib Design & Communications www.craib.com Printed in Canada

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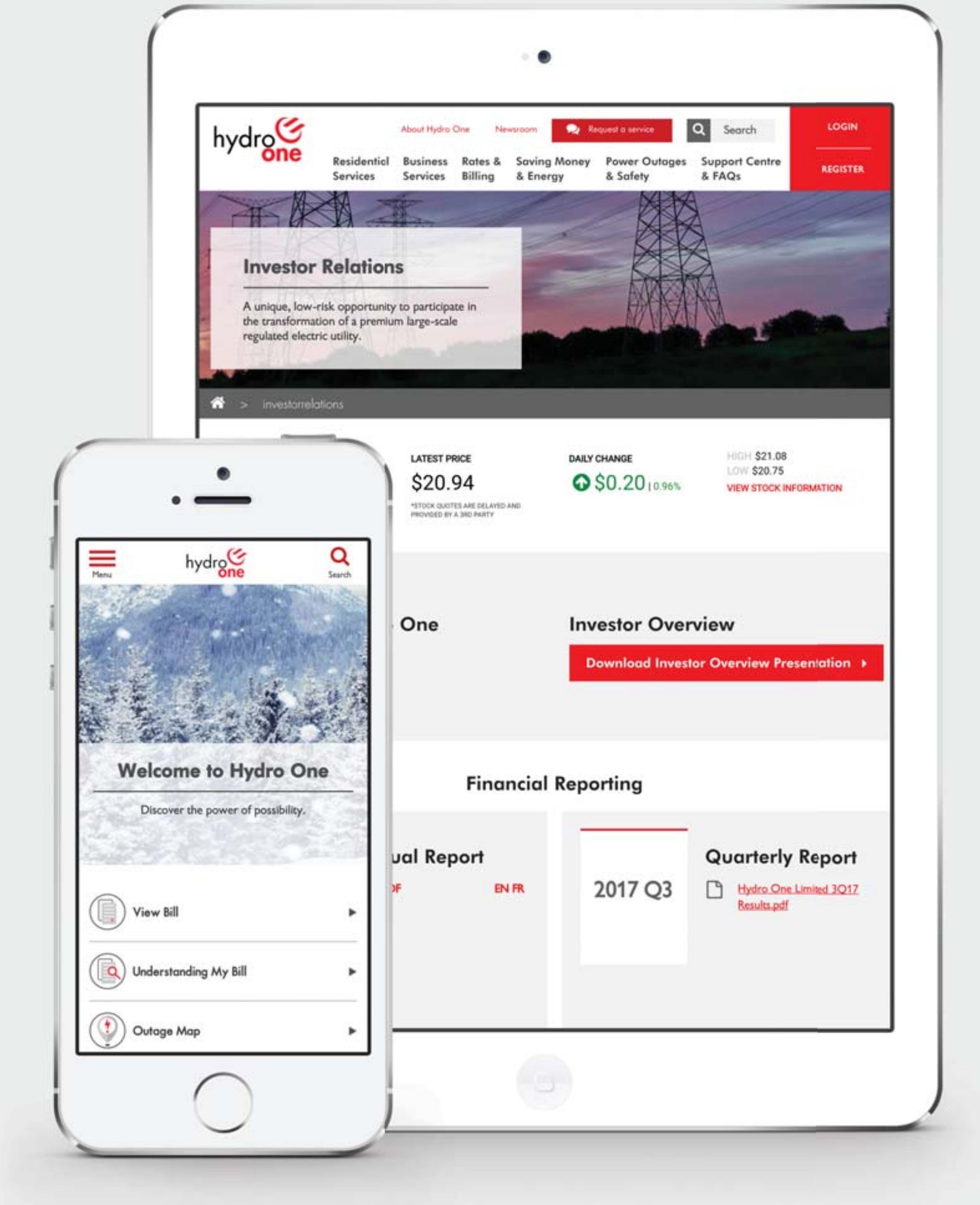
WHY INVEST WITH HYDRO ONE LIMITED?

Investing in Hydro One offers a unique opportunity to participate in the transformation of a premium large-scale utility. We offer a strong investment grade balance sheet, predictable multi-year growth with strong cash flows and an attractive dividend. Our highly accomplished management team is taking the opportunity to transform the organization into a commercially oriented, performance-driven culture focused on improving productivity and customer service.

www.HydroOne.com



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TAB 4

FIRST NATIONS CUSTOMERS

SUMMARY

There is a greater amount of dissatisfaction among First Nations residential customers when compared to Residential customers overall. Of all of the R&SB segments, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive. However, First Nations customers are as likely to accept the proposed 1% increase on the total monthly bill to maintain the current level of reliability and customer service.

TELEPHONE SURVEY

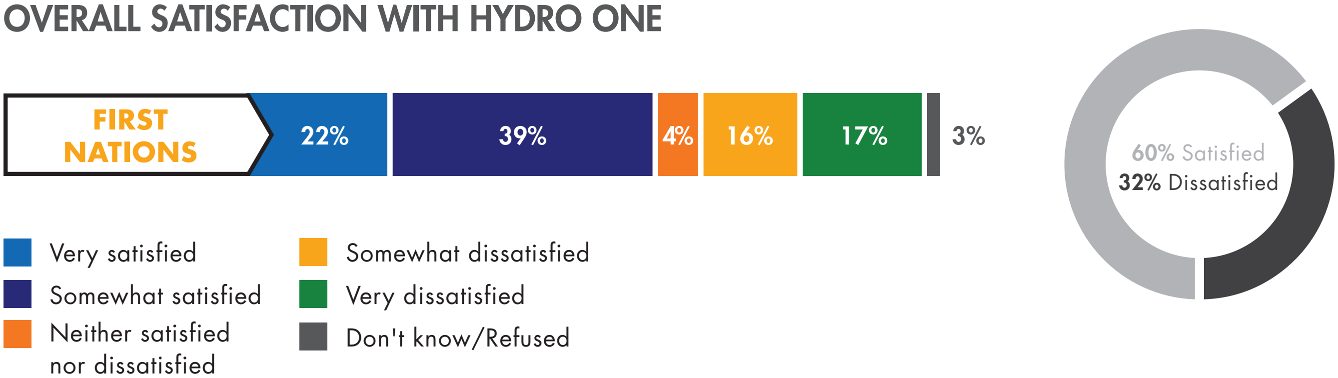
As outlined in the methodology section of this report, the following results are based on a Telephone Survey of a random and representative sample of n=300 First Nations customers. A stratified, random sampling approach was used to pull the sample from Hydro One's customer database. With a sample of this size, the results are considered accurate to within ± 5.7 percentage points, 19 times out of 20, of what they would have been had all First Nations customers been surveyed. That means that if the survey is repeated 20 times, 19 of those times the results of the survey will be the same within the margin of error. The margin of error will be larger for sub-groups of the population. This data was not statistically weighted because the unweighted sample composition closely matches the true regional and urban/rural proportions in the customer database. For more information on the survey methodology refer to the Customer Engagement Methodology Section of the report.

CURRENT SATISFACTION AND WHAT IS IMPORTANT TO CUSTOMERS

Six-in-ten (60%) of First Nations customers report they are satisfied with Hydro One overall, while one-third (32%) are dissatisfied. When asked on an unaided basis what Hydro One can do to improve its service, the most frequent answer customers give is to reduce their monthly bills. Some customers mention this in the context of lower prices or lower rates, while other just simply say lower cost.

TELEPHONE SURVEY

OVERALL SATISFACTION WITH HYDRO ONE



As you may know, Hydro One builds and maintains power lines, towers and poles, safely delivers electricity, reads meters, calculates your charges, answers your calls, responds during outages, and clears trees and brush from power lines. Hydro One does not generate electricity or set electricity prices. Q1. Please think about Hydro One as I have just described it to you. How satisfied are you with Hydro One overall? Note: During the first week of fielding the response scale was changed from1 to 5 to a word scale to be consistent with the Annual Customer Satisfaction survey. Base: All Respondents Post Q change, First Nation (n=204)

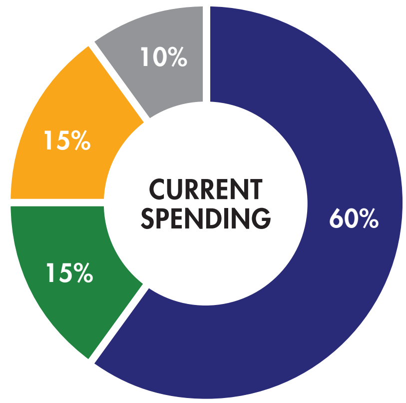
Given the opportunity to review a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments, that is, how the distribution delivery rate is allocated, half (52%) indicate they would not change how the money is currently allocated. Two-in-ten customers indicate they would change how the money is allocated.

In general, these customers allocate more money to restoring power after outages, doubling the amount of spending on it. They allocate more money for upgrading the system to connect new customers, including those producing renewable energy, by about 50%. They allocate less money to keeping the system reliable, reducing the amount by nearly half.

TELEPHONE SURVEY

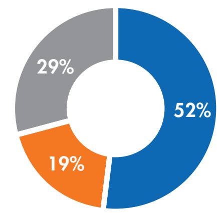
OPINIONS ON CURRENT ALLOCATION OF SPENDING

- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage



CUSTOMERS' REACTION TO SPENDING ALLOCATION

FIRST NATIONS



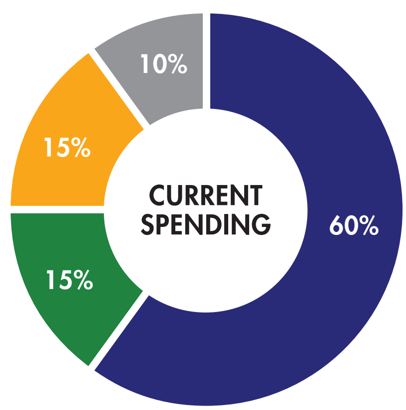
- Keep the same
- Change
- Don't know/Refused

Q3. Please listen carefully as I will be reading out a rough breakdown of what Hydro One currently spends on each of its major electricity distribution investments and will be asking your opinion about the breakdown. Hydro One currently spends [READ LIST]... If you were in charge of Hydro One would you change how spending is allocated or would you keep it about the same as it now? Base: First Nations (n=300)

TELEPHONE SURVEY

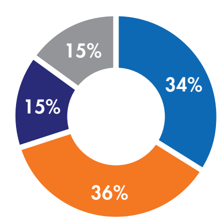
PREFERRED ALLOCATION OF SPENDING

- Keeping the system reliable such as replacing worn out equipment, trimming trees to keep power lines clear
- Restoring power after an outage
- Customer service and billing such as providing customer service through your phone or online, providing tools so you can manage your energy use, ensuring accurate and timely bills
- Upgrading the system to connect new customers including those producing renewable energy or using energy storage



CUSTOMERS' PREFERRED ALLOCATION OF SPENDING

FIRST NATIONS



- Keeping the system reliable
- Restoring Power
- Customer Service
- Upgrading the system to connect new customers

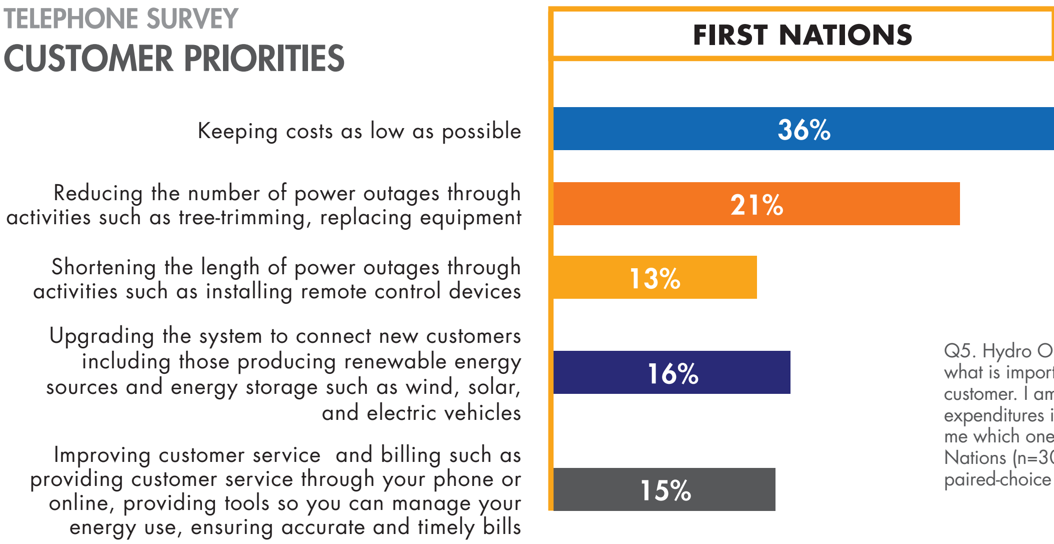
Q4. Of the 4 distribution investments you just heard, what percentage would you allocate to...? Base: Customers who indicated that current spending should be changed. The percentages have been rebased to exclude don't know responses or responses that do not add to 100% (First Nations n=54)

CUSTOMER PRIORITIES

The chart below shows that keeping costs as low as possible has a relative preference score of 36% among First Nations customers, which is the largest preference score of the options presented.

This indicates that customers prioritize keeping costs as low as possible above the other options – reducing the number of outages, improving restoration times, improving customers service, or upgrading the system to connect new customers. It is more than twice as important to customers as the latter three options (restoration times, customer service and connecting new customers). Reducing the number of outages is the next more preferred option.

TELEPHONE SURVEY
CUSTOMER PRIORITIES

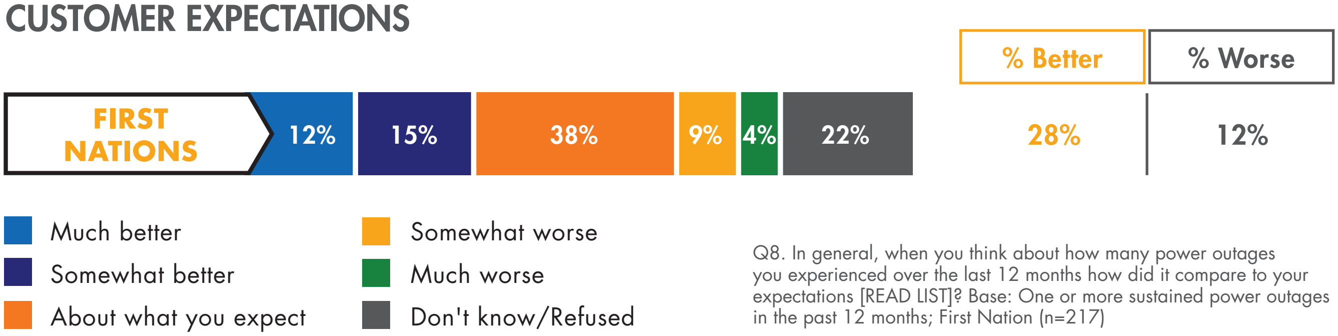


Q5. Hydro One would like to better understand what is important to you as a residential customer. I am going to read Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Base: First Nations (n=300) Pair-choice analysis paired-choice preferences relative to other options.

THE LEVEL OF RELIABILITY THAT CUSTOMERS EXPECT

Most customers indicate the level of reliability they currently experience is at least in line with their expectations. First Nations customers report experiencing an average of roughly three outages of at least one minute in length in the past 12 months. The largest share of customers (38%) indicate that this level of reliability (number of outages they experienced) is about what they expect. Only 12% of customers who experienced at least one outage indicate the number of outages they experienced is worse than they expect.

TELEPHONE SURVEY
CUSTOMER EXPECTATIONS



Q8. In general, when you think about how many power outages you experienced over the last 12 months how did it compare to your expectations [READ LIST]? Base: One or more sustained power outages in the past 12 months; First Nation (n=217)

When it comes to length of outages, First Nations customers estimate that the outages they experience last an average of 3.7 hours. Similar to opinions of the frequency of outages, the largest share of customers indicate that this is about what they expect. Sixteen percent say this is worse than they expect.

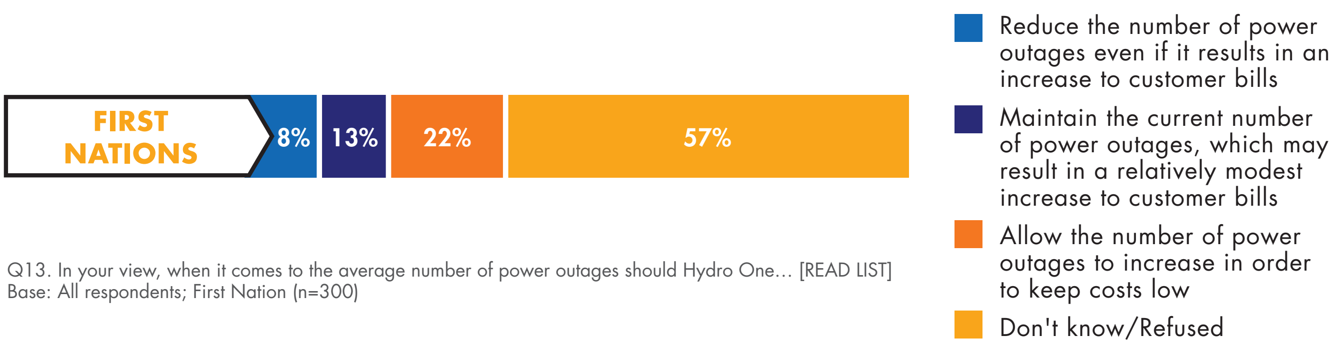
HOW CUSTOMERS REACT TO SERVICE VS. COST TRADE-OFFS

Half (57%) of First Nations customers do not offer an opinion on how Hydro One should approach the issue of outages. Of those that do, opinions are generally split, with one-half willing to accept more outages and longer outages to keep rates as low, while the other half are willing to accept a modest increase to maintain the current number of outages or a larger increase to see fewer outages.

TELEPHONE SURVEY

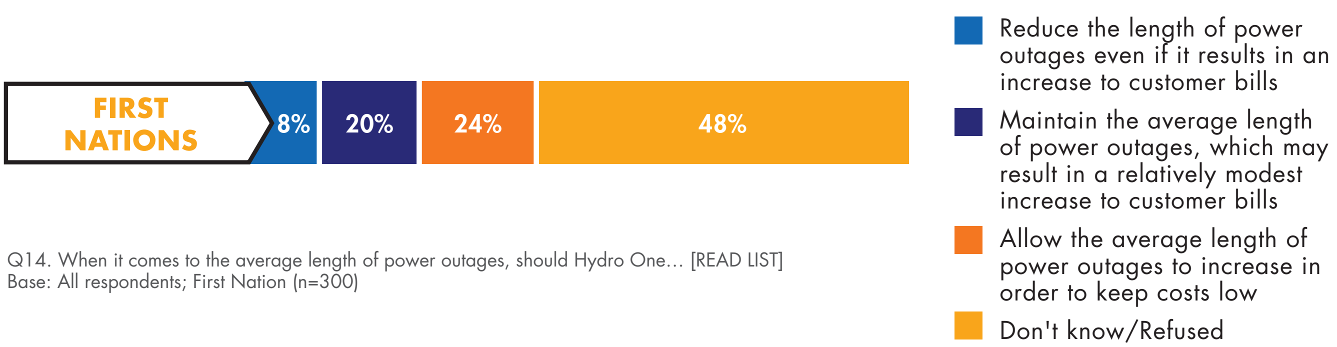
RELIABILITY TRADE-OFF PREFERENCES

NUMBER OF POWER OUTAGES



Q13. In your view, when it comes to the average number of power outages should Hydro One… [READ LIST]
Base: All respondents; First Nation (n=300)

LENGTH OF POWER OUTAGES

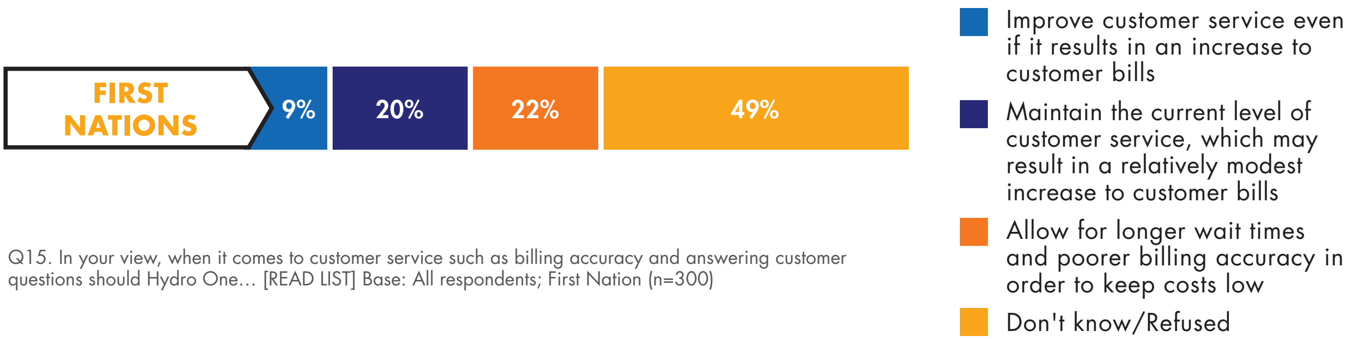


Q14. When it comes to the average length of power outages, should Hydro One… [READ LIST]
Base: All respondents; First Nation (n=300)

TELEPHONE SURVEY

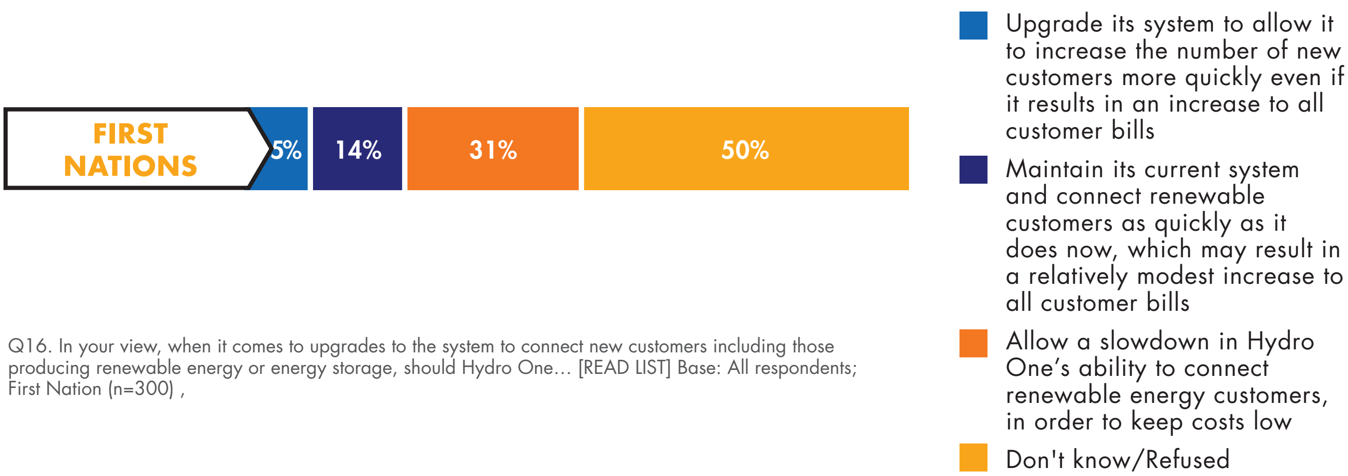
OTHER TRADE-OFF PREFERENCES

CUSTOMER SERVICE



Q15. In your view, when it comes to customer service such as billing accuracy and answering customer questions should Hydro One… [READ LIST] Base: All respondents; First Nation (n=300)

CONNECTING CUSTOMERS PRODUCING RENEWABLE ENERGY



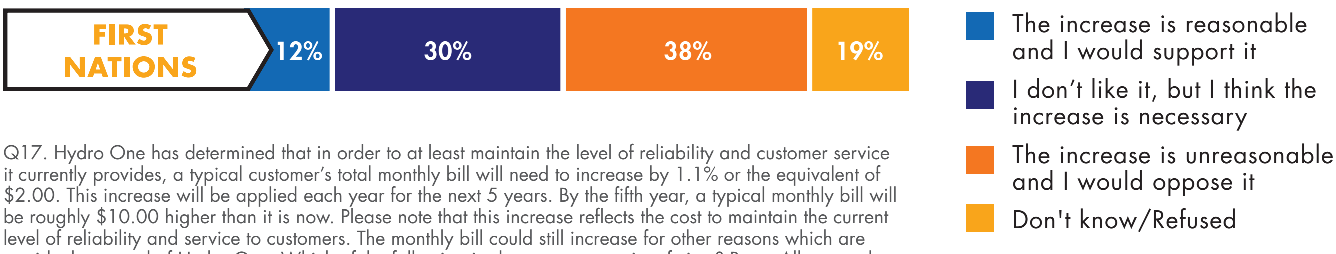
Q16. In your view, when it comes to upgrades to the system to connect new customers including those producing renewable energy or energy storage, should Hydro One… [READ LIST] Base: All respondents; First Nation (n=300) ,

WILLINGNESS TO ACCEPT A RATE INCREASE TO MAINTAIN AND IMPROVE SERVICE LEVEL

When customers are informed that Hydro One has estimated that in order to **at least maintain** the level of reliability and customer service it currently provides, a typical Residential customer's **total monthly bill** will need to increase by 1.1% or the equivalent of $2.00, 42% of First Nations customers are willing to accept it, 38% are opposed and the remaining 19% do not offer an opinion.

TELEPHONE SURVEY

ACCEPTABILITY OF RATE INCREASE TO MAINTAIN LEVELS



Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical customer's total monthly bill will need to increase by 1.1% or the equivalent of $2.00. This increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly $10.00 higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Which of the following is closest to your point of view? Base: All respondents; First Nation (n=300)

Prior to answering this question, customers were informed that the increase of $2.00 would be applied each year for the next five years, and that by the fifth year a typical monthly bill will be roughly $10.00 higher than it is now. Customers were also informed prior to answering that the increase reflects the cost to maintain the current level of reliability and service to customers, and that the monthly bill could still increase for other reasons which are outside of Hydro One's control.

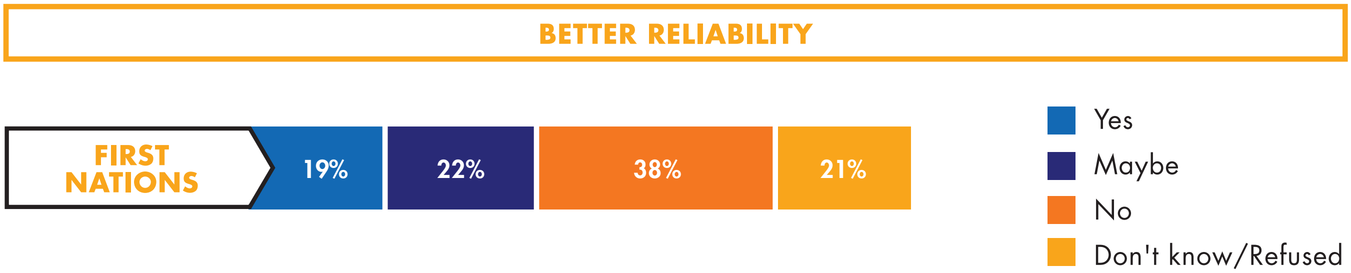
First Nations customers are more willing than others to pay more than $2.00 to have better reliability than they have now, although those holding this opinion still represent a minority. Two-in-ten (19%) customers indicate they would be willing to pay more than the $2.00 (1.1%) increase in order to have **better reliability** than they have now. An additional 22% would consider it (selecting 'maybe' as their response).

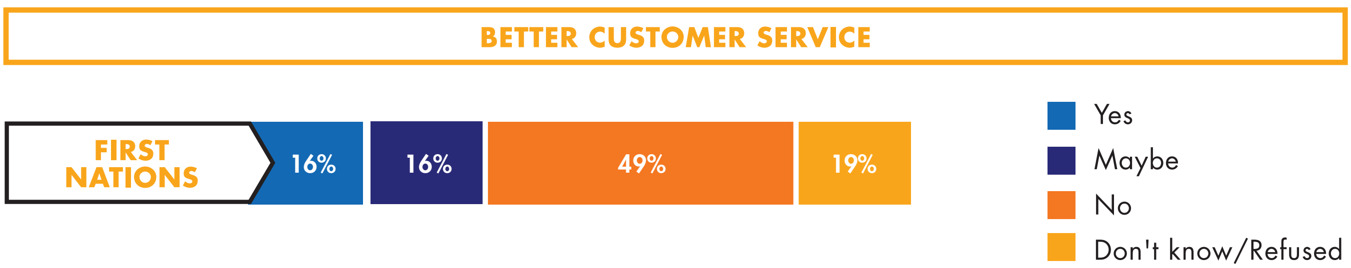
Unlike the 73% of Small Business customers who would not pay anything more or even Residential (off-reserve) customers where 64% would not, 38% of First Nations customers oppose, and 21% say they don't know/ refuse to answer. There is less interest in paying for an improved level of customer service, with only 16% saying they would be willing to pay extra for improved customer service, 16% saying maybe and 49% saying they would not.

Lastly, customers were asked about their level of interest in a 10% reduction in the number and length of future power outages, for a specific rate impact. Two additional rate impacts were posed to customers for their reaction. Half of the sample of respondents were asked to consider an additional $0.30 per month, or a total of $2.30 more (or $11.50 in the fifth year) on their monthly bill, and the other half was asked to consider a rate increase of $0.60 per month, or total of $2.60 more (or $13.00 by the fifth year) on their monthly bill.

TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS





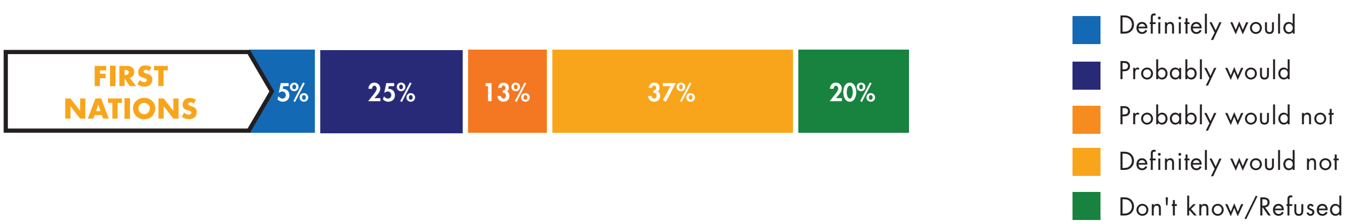
Q18. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have a better reliability than you have now? Q19. Would you be willing to pay anything higher than the $2.00 or about 1.1% more on your total monthly bill if it meant you would have better customer service than you have now? Base: All respondents; First Nation (n=300)

Of those who were asked to pay an additional $0.30, only 30% of customers say they would prefer (definitely or probably would) to pay more, while 50% say they definitely or probably would not. Of those who were asked about an additional $0.60, 20% definitely or probably would and 58% definitely or probably would not.

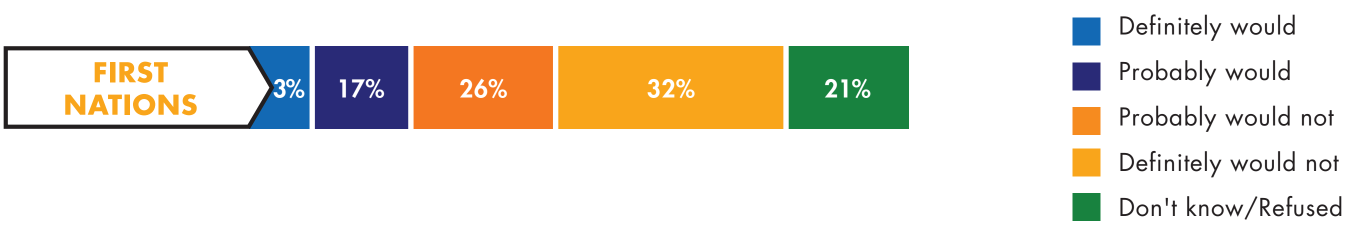
TELEPHONE SURVEY

WILLINGNESS TO PAY FOR IMPROVED LEVELS

ADDITIONAL $0.30



ADDITIONAL $0.60



Q20A. Would you be willing to pay an additional [HALF OF RESPONDENTS SHOW $0.30/OTHER HALF SHOW $0.60] per month over and above the $2.00 which would be approximately [SPLIT SAMPLE $2.30/$2.60] more per month if it meant that Hydro One could reduce the number and length of future power outages by 10%? The increase would be applied annually for the next five years so that by the fifth year your monthly bill will be roughly [$11.50/$13.00] higher than it is now? Base: SPLIT SAMPLE FIRST NATIONS (n=150 were asked about each impact level)

TAB 5

Hydro One and First Nations Engagement Session
Mandarin Room, DoubleTree by Hilton
Thursday, February 9, 2017

SESSION REPORT

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Note Taking Summary of Hydro One Key Messages

- There is a new team at Hydro One who is committed to working with First Nations through honest and respectful engagement.
- Hydro One is working to improve service, responsiveness, and reliability of the power system.
- Hydro One committed to finding solutions to address the affordability challenges faced by First Nations.

Note Taking Summary of First Nations Key Messages

- Hydro rates are burdensome for many First Nations, in particular for Elders and vulnerable people. There needs to be immediate and significant action to mitigate the high costs.
- First Nations are interested in exploring the idea that a unique rate for First Nations should apply to First Nations people both on and off reserve.
- First Nations must enjoy the benefit of resources that are drawn from their territories.
- Hydro One staff working in First Nations communities needs some level of cultural awareness training. This should include knowledge about land regimes and treaty relationships.
- Many First Nations are willing to engage with Hydro One in order to achieve results for First Nations communities and people.

WELCOME

Mr. Phil Goulais, Session Facilitator: Mr. Goulais began the meeting by introducing Elder Andrew Wesley who provided an opening prayer and a smudge. Chief Reginald Niganobe, of Mississauga #8 First Nation, welcomed the participants on behalf of the Mississauga Nation, the host territory for the meeting, thanked the Elder for the prayer and acknowledged the sacred items in the room.

Mr. Goulais introduced himself to the room as a member of the Nipissing First Nation, where he was the Chief for many years. He is currently working part time on a contract with Hydro One, which has allowed him to work in many First Nations communities. He thanked the participants for sharing their knowledge and welcoming contractors into their communities with kindness. This work was part of a commitment to relationship building, which is still ongoing. Mr. Goulais shared that he expected many of the topics discussed on those community visits would be discussed at this session: Hydro One billing system sessions; career opportunities at Hydro One; and, procurement workshops for First Nations businesses.

Mr. Goulais reflected that in their conversations with communities, First Nations leaders have expressed an interest in impacting policy development and/or change with Hydro One. Both First Nations and Hydro One leadership are seeking to establish how to work together better. This engagement session is a response to that shared goal of working together better. With this in mind, Mr. Goulais expressed the goal of the engagement session: to hear First Nations' priorities; to share current thinking; and, to solicit feedback on the upcoming Distribution Rates submission to the Ontario Energy Board. The agenda attempts to balance information sharing from Hydro One and discussion.

Mr. Goulais thanked the Hydro One staff for working hard to make the engagement session happen. He also thanked the Chiefs, Councillors and other participants. He also noted the presence of the Ontario Regional Chief, Isadore Day and Grand Chiefs in the room.

Mr. Goulais concluded by noting the participation of senior leadership at Hydro One, which demonstrates a clear willingness to work with First Nations. It was noted that notes of the meeting are being taken and participants would receive the written notes of the session for review.

INTRODUCTIONS

The participants were asked to provide their name, where they are from and their expectations for the gathering.

Lisa Kooshet, Councillor, Wabigoon Lake First Nation: Ms. Kooshet came to the meeting looking for information to inform the development of the Wabigoon Lake First Nation community energy plan

Chief Brian Perrault, Couchiching First Nation: Chief Perrault was attending the meeting with an expectation of talking about on-reserve hydro rates and the potential for eliminating the distribution rate on hydro bills. He noted that, in many of communities, Elders and others have to decide between paying the hydro bill or putting food on the table. He noted that his community is close to Fort Frances, which has low hydro rates because of the nearby dam, which generates power. However, reserve lands had to be flooded to build that dam. First Nations have paid a price for the low energy rates that Fort Frances enjoys. Chief Perrault came to this session to identify how we can lessen the financial burden on Elders and others.

Jerry Fontaine, Hydro One Contractor: Mr. Fontaine noted that he has been involved with Hydro One for many years. He reiterated the comments from Chief Perrault related to the struggle to sustain basic standards and the need to decide between food and light. This is a struggle alongside the struggle for housing, economic development and employment opportunities. Mr. Fontaine recognized Ms. Lee Anne Cameron (Hydro One's Director of First Nations and Metis Relations), for initiating this discussion and saw the meeting as an opportunity for change. He concluded that he is part of Treaties 1 and 3, and that historically Treaty 3 did not recognize the border.

Phil Goulais, Hydro One Contractor: Mr. Goulais shared that he was looking forward to network throughout the day and was also acting as the Master of Ceremonies for the dinner in the evening.

Mayo Schmidt, President and CEO of Hydro One: Mr. Schmidt welcomed everyone and thanked them for their participation and openness to dialogue. He also thanked Ms. Cameron for organizing the event. He suggested that hearing from participants presents a great opportunity to act on the things that they, as Hydro One, learn through the discussion.

Lee Anne Cameron, Director, First Nations and Metis Relations, Hydro One: Ms. Cameron thanked the participants for attending the session today.

Chief Reginald Niganobe, Mississauga #8 First Nation: Personal introduction

Chief Gerry Duquette Jr., Dokis First Nation: Personal introduction

Darryl Hill, Community Energy Planner, Six Nations of the Grand River Territory: Personal Introduction

Chief Warren Tabobondung, Wasauksing First Nation: Chief Tabobondung noted that they have many issues around Hydro One in his area, including development and power generation dams. These have a significant impact on the hunting, fishing and gathering for his people. Flooding was identified as a challenge. He shared his expectation of the meeting to exchange information about whom his people are and how they are impacted. He also noted that he wanted to talk about the high cost of hydro, which put their Elders in a position to choose between food and light. The Elders are the people who have persevered through so much change. Chief Tabobondung noted that the issue is also about land and the fact that Crown assets (i.e.- transmission lines) are sitting on Treaty territories. Reducing hydro rates by a few percentage points is not going to solve these bigger issues. He noted that he would like the discussion to get to these bigger issues. He also recognized that things have changed including the increasing voice of First Nations since the 1960s. He is optimistic and willing to exchange information and ideas and work together to resolve the issues facing his community.

Karen Taylor, Hydro One: Ms. Taylor stated she was attending the meeting to listen and learn.

Chief Tom Bressette, Kettle and Stony Point First Nation: In attending today, Chief Bressette shared his hope to examine ways through government engagements. He suggests looking at the Treaties; his is from pre-Confederation. He continues to observe political leaders, Trudeau and Wynne, making commitments about partnerships. However, in reality there does not seem to be much going on. There are a lot of promises but little financial commitment. Chief Bressette reiterated the earlier comments about economic insecurity and the impact on communities including Elders and youth. This is particularly challenging in the winter and impacts mental wellness. He noted that he has seen promises from governments before and challenges them to move from talk to action. He also noted that he sees Hydro One going through challenges, trying to sell off assets, with human resources issues and aging infrastructure. These things cost money and are the reason why hydro rates are so high. However, Chief Bressette reminds attendees that the Treaty talks about sharing resources, yet he sees everyone but his people benefitting from First Nations resources. This is also part of honouring the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP). He also expressed frustration over having to go back to his community without an answer for high hydro rates. He is no longer “asking” for a response, he is “demanding” a response. It is time to share these resources.

Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One: Mr. Pugliese expressed thanks to Mr. Goulais, Mr. Fontaine, Mr. Kakeway and everyone who worked on this event. He noted that Hydro One wants to list en an act on the things that they can and capture the attendees’ comments.

Councillor Ted Williams, Chippewas of Rama: Chief Williams stated he was attending to listen and hear some other issues out there. He said he was pleased for the opportunity to dialogue, but that action is best.

Chief Greg Nadjiwon, Chippewas of Nawash Unceded First Nation: Chief Nadjiwon noted he shared many of the previous comments from Chief Tom Bressette. He stated that he was attending to find out how to collectively move forward in true partnerships, true resources sharing and open and transparent communication. He notes that three decades ago the corporate mindset was flood the lands and deal with the rest after; however, the corporate mindset has changed towards Indigenous relations. For his community it has been a success story; they have a contact and the results happen quite quickly. The results are not always positive, but they get answers more quickly. He views this engagement as an opportunity to move the yardstick, to have a constructive day and network.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): Chief Miskokomon notes that the Minister of Energy asked how we can change thinking. However, from his perspective Crown corporations do not listen to First Nations. Crown corporations must remember that they are accountable to First Nations and citizens, meaning they need to be more transparent in the way activities are undertaken and services delivered in his territory. He notes the changing tide, as evidenced by the Truth and Reconciliation Commission of Canada (TRC). There must be meaningful partnerships. Hydro distribution costs are very high. The Chief also identified the need for Hydro One staff to undertake cultural sensitivity training. Working with First Nations requires getting to know First Nations. In addition, Chief Miskokomon cited the need to look at alternative energy. This also means supporting First Nations in becoming educated on what is out there and ensure capacity within First Nations. This requires professional support in establishing First Nations owned and run utility companies on-reserve that will not include redistribution costs. All of these ideas require people to be more creative. The Chief reminded the group that non-Indigenous people are still visitors in the territory. Partnerships must be built based on trust.

Chief James R. Marsden, Alderville First Nation: Chief Marsden also shared support for the words of Chief Bressette. As far as this meeting, he was interested in discussing “blanket agreements.” What is it? He notes that in the ‘Addition to Reserve’ process, Indigenous and Northern Affairs Canada (INAC) asked for blanket agreements. They have never had a blanket agreement with Hydro One and asked if this type of agreement was required for his reserve.

Marlene Stiles, Manager of Economic Development, Chippewas of Georgina Island: Ms. Stiles commented that she was attending to listen, learn and take information back to her community.

Marvin Sinclair, Elk Clan, Band Manager, Washagamis Bay Obashkaandagaang: Mr. Sinclair noted that he has previously been on Council and been the Chief of his community. He also shared that his brother was the Chief of his community and passed on last week. The First Nations in the room all share the same challenges, including broken promises and poor people. Mr. Sinclair recently moved back to his community from Sault Ste. Marie and can see the difference in hydro rates between the reserve and the urban centre. He notes this will be a common theme of the day. He also articulated that when people talk about "resource" they are actually talking about the source of life, which is worth much more than a dollar sign. First Nations have a connection to the land. If even a fraction of the Treaty promises were honoured there would be no need to have these discussions. Rather, First Nations would be financially independent and stable. Mr. Sinclair suggested it was a privilege to be a part of the conversation and hoped that Hydro One officials would heed what they heard.

George Kakeway, Hydro One Contractor, Rat Portage: Mr. Kakeway stated that it was nice to see many old friends at the engagement event. He noted the importance of the session in terms of engagement. In addition, he shared that most of his work is done in Treaty 3 communities. He noted that there was diversity between communities, but there were also universal issues including delivery charges. He saw this session as an opportunity to engage, move forward and see how the communities could be helped.

Joe Cheechoo, Elder Councillor, Moose Cree First Nation: Elder Cheechoo shared that he was attending the session to better understand how the hydro system works.

Chief Patricia Faries, Moose Cree First Nation – Chief Faries began as Chief last August and was happy to attend the meeting. She sees engagement as the important first step. A meeting was held in her community on January 10, 2017and the primary concern that was raised related to hydro was outrageous delivery charges. She shared that she is on a fixed income and wants to understand what can be done to address these charges. She sees people suffering under the delivery charges. She notes that her community signed an agreement with Ontario Power Generation (OPG). She also wonders what is the fiduciary duty Hydro One has to her community and all First Nations. She also notes that she expected to hear clarity at this meeting because her time is precious, and hydro is just one of the many issues she needs to address. She suggests that reconciliation means that there must be a discussion about the benefits that Hydro One enjoys at the cost of First Nations land use. She sees Hydro One using Indigenous land only to sell hydro back to Indigenous people. She notes that she has to have tangible things to report back to her people and is expected to report back on February 21, 2017. She also reminded the room of the Lower Mattagami project, right in her community's back yard that included four (4) dams built from 1960 to 1966. Former leaders signed an agreement. Yet today these dams have to be fixed. She suggested that the conversation focus on what is possible from Hydro One and how Hydro One can help her people right now.

Chief Leslee White-Eye, Chippewas of the Thames: Chief White-Eye echoed the words of the previous speakers. She noted the need for some discussion on the corporate history of Hydro

One. She also expressed that there is a need for the federal government to participate in these discussions because of permitting and issues related to lands. She was also seeking a contact person within Hydro One who could discuss negotiating this new payment and who will pay for it.

Errnol Gray, Councillor, Aamjiwnaang First Nation: Councillor Gray noted he was participating to listen, but also to discuss the line crossing at the St. Clair river, which goes through First Nations and the Treaty area. He also noted that he is on a fixed income and has trouble paying his high hydro bills. His community signed an agreement in 1953 and the payments have not increased since. He suggests a new agreement needs to be negotiated.

Chief Melvin Hardy, Biinjitiwaabik Zaaging Anishinaabek: The Chief thanked the host for allowing them on their traditional lands as well as thanking his friend Elder Andrew Wesley. Related to the importance of land, the Chief noted that the youth go out on the land and sustain a relationship with, and right to, the land. He described his First Nation, which is found on the southeast side of Lake Nipigon. He suggested that Hydro One officials needed to spend some time living in some of the homes in his community. He wondered, if the government does not give First Nations authority over their own lands, why would Hydro One do it? He noted that it is cold in First Nations communities, which contributes to Elders and children getting sick. This is exacerbated when the power goes out. There is no compensation when the power goes out and communities are forced to collect their own wood and go without. Chief Hardy noted that his community is constantly in deficit because of high costs of hydro. He also identified that there had not yet been an engagement session in his community and that it needed to happen.

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: Mr. Hubert welcomed the kinds of comments that attendees had been sharing as it is important for him, as a Hydro One official to understand the issues.

Edward Skeid, Councillor, Wauzhushk Onigum First Nation: Councillor Skeid asked that Hydro One staff stake the comments made by the attendees seriously and take them to their superiors.

Deputy Chief Fabian Blackhawk, Ochiichagwe'babigo'ining Nation (Dalles): Deputy Chief Blackhawk began by acknowledging the sacred items in the room and the prayer from the Elder. He noted that he certainly relates to the comments made so far. He was looking for some direction on what this meeting is supposed to accomplish. He also shared that leaders and youth have told him many of the things that were already mentioned. It is tough to see all these people making money off First Nations resources and lands with First Nations people in poverty. His community signed an agreement for the hydro lines and cannot make any adjustments. Of the session, he expected an open dialogue to make good decisions to take back to his people.

Harold Thiessen, Ontario Energy Board: Mr. Thiessen expressed his intention to listen and learn.

Gary Schneider, Vice President of Shared Services, Hydro One: Mr. Schneider shared that he works on procurement as well as land matters. When it comes to the issue of land he has heard the frustration in the room and agrees that agreements with First Nations need to move forward.

Amy Lickers, Chiefs of Ontario: Ms. Lickers introduced herself as coming from Six Nations and works with the Chiefs of Ontario Chiefs Committee on Energy. She noted she attended the session to listen.

Yvette Maiangowi, Energy Planner, Wikwemikong Unceded First Nation: From her perspective, Ms. Maiangowi notes that nothing has changed; in fact the situation in her community has worsened. She also asked those in the position to negotiate agreements with First Nations to stand up. She noted a need for a clear path forward including timelines. She concluded by saying that the time for talking has passed.

Craig Aldred, Wahgoshig First Nation (Abitibi #70): Mr. Aldred noted a need to address distribution costs, as these high costs negate their efforts to build sustainable communities when the costs end up being covered by the bands. He expressed a need to develop long term solutions.

Rob Globocki, Director, Customer Care, Hydro One: He expressed to the participants that he was also here to listen and learn.

Sara Mainville, Associate, Olthuis Kleer Townshend LLP: Ms. Mainville introduced herself as an advisor to Regional Chief Day. She also does work with Grand Chief Peters on Hydro One opportunities. Ms. Mainville expressed that she was happy to attend and see many Chiefs in attendance.

Grand Chief Gord Peters, Association of Iroquois and Allied Indians: Grand Chief Peters noted that the Hydro One process has been a long process that they have been involved in for some time. He also acknowledged Chief Ava Hill from Six Nations for working on this issue. At the last All Ontario Chiefs Conference (AOCC), there was a meeting attended by the new Minister Thibeault who committed to developing a First Nations rate. This commitment was made 8-9 months ago. This remains the issue for the discussion at this session. He posed a number of questions including, what is the rate going to look like and how will that be brought to our communities? He heard that the distribution charge is one of the easier things to change, so wanted a commitment on that. He noted that should Ontario continue to privatize beyond 60% of Hydro One, the province would remain liable for all the damages that continue to flow. His community is the same as Alderville in that there are no agreements in place. They are dealing with the Additions to Reserve process and are 12 years in. He reminded the attendees that "you have to have full permit or cannot move ahead". His community is still in the talking stages. He suggested that these are the things that become irritants in the process. In order to move forward, Grand Chief Peters says that we have to learn how to get along and there will have to be a better arrangement for First Nations.

Chief Jim Leonard, Rainy River First Nation: Chief Leonard describes his community as between Thunder Bay and Winnipeg near the American border. His community had engaged with Hydro One a number of years ago where they talked about past grievances and decided they need to set those aside to move forward. They acquired, constructed and commissioned a solar farm. Without technical support or shared engagement with Hydro One it is difficult to make these things happen. He was attending the engagement session to advance that process. He saw it as important for Hydro One to listen to the grievances shared because they still impact First Nations, but also recognize that First Nations are ready to move forward. There is the potential for this to be a revenue stream and support to communities.

Deputy Grand Chief Derek Fox, Nishnawbe-Aski Nation (NAN): Deputy Grand Chief Fox began by thanking the Elder for the prayer. He described NAN as being comprised of 49 First Nations and 7 tribal councils. NAN communities extend from the Manitoba border to James Bay. This is a huge land mass and most communities are remote. People in these communities are passionate about their hunting, culture, water, river systems and language. Deputy Grand Chief Fox noted that he is from Treaty 3, Shoal Lake 40 where there are profound water issues. When he was younger he was driven to become a lawyer and learn the systems that govern. He expressed concern over claims to jurisdiction over Indigenous lands. He concluded by sharing that he was participating in the session to support NAN Chiefs, to listen, to talk about NAN initiatives and hoped to have a meaningful discussion.

Jamie Scarlett, Executive Vice President, Chief Legal Officer, Hydro One: Mr. Scarlett commented that he was attending the session primarily to listen and learn. Within his duties, he has some involvement in rates so hearing from the First Nations participants was impactful for him. He noted that he is appalled at how long it takes for Hydro One to deal with these issues. He offered his personal commitment to drive these issues forward to be dealt with in a clear, open, transparent and timely way. He reflected that he had heard the message that 'these are just words, but First Nations want actions.

Chief Ted Roque, Wahnapitae First Nation: Chief Roque began by thanking the Elder and acknowledging the land where the meeting was held. He was attending the meeting to hear more about new rates. He noted that it would be great to see lowered rates and it would make a huge difference for his people. He recognized that there is only one year left in the Wynne government's mandate and he does not want to see these discussions get lost; whether the next Premier is Wynne or someone else, these negotiations must continue. He noted that there must be more sharing of resources and opportunities and true partnership.

Andrew Wesley, Elder: The Elder introduced himself as hailing originally from Fort Albany, but has been living in Toronto for many years. He shared that traditionally electricity was known as Thunderbird Fire. This demonstrates the close relationship between First Nations and mother earth.

Deputy Chief Kevin Mossip, Zhiibaahaasing First Nation (Cockburn): Deputy Chief Mossip shared that in his community hydro rates increased 72% in two years and this increase has caused hardships. He brought a message from his Council that the engagement session was in no way, shape or form to be considered consultation. In addition, his community would not agree to anything unless the hydro rates were lowered by 72%

Warren White, Councillor, Naotkamegwanning First Nation: Councillor White came to the meeting to speak for his community and see the faces of Hydro One. He notes that his Elders, the ones who are struggling, are paying the wages of Hydro One staff. He provided a welcome to the Chiefs, Grand Chiefs and Councillors. He noted that he knows how it feels to be accountable to the Chiefs and the community. He met with 35 Elders in his community last week. They told him that the HST rebate does not impact their hydro bills. Each of those Elders was paying over $1,000. He notes that he burns wood and his bill is still $1,000. He states that he did not want to attend the meeting and did not want to hear the same rhetoric from Hydro One. There is a lack of trust with Hydro One. The delivery charges in his community average out to about $250 each month, which amounts to $50,000 a month for the whole community. Councillor White suggested that he plans to charge Hydro One double that amount to enter his community; this includes any hydro trucks. When Prime Minister Trudeau had his town hall recently there was a woman crying about hydro and the media was all over that. Yet when it comes to First Nations and their hydro rates, there is no media. He said something has to be done. He suggests that his community does not support Hydro One dealing through the Chiefs of Ontario as there are too many grievances that need to be dealt with including the dams in Treaty 3 and the flooding. He asked what Hydro One was willing to do about it. He expressed skepticism as he views Hydro One as only being motivated by money. He concluded by reaffirming that something has to be done otherwise his community would start charging Hydro One to come in.

Annette Currie, Technician, Pic Mobert First Nation: Personal Introduction

Deanna Major, Councillor, Animakee Wa Zhing #37: Councillor Major expressed that she would like to see the salary disclosure for Hydro One and an explanation of how those salaries are justified.

Gary Allen, Executive Director, Grand Council Treaty #3: Mr. Allen introduced himself and that he was attending on behalf of Grand Chief Francis Kavanagh, who is travelling with Minister Zimmer in Treaty 3 territory. Last year, prior to a meeting between Hydro One and Grand Chief White, Treaty 3 citizens were asked to send their hydro bills. They brought a binder full of these bills that demonstrated the exorbitant costs faced by his people. He also noted that he checked the sunshine list for Hydro One and saw over 600 employees earning more than $100K. He found this incredible considering the suffering in First Nations communities. He shared his support for the Great Earth Law, the Sacred Law, and also the laws of the 28 First Nations in Treaty 3.

Lance DeCaire, Technician, Wahta Mohawks: Mr. DeCaire noted that the most pressing issue facing his community is the delivery charges and the impact that those high delivery charges have on the success of the community's economic development initiatives.

Chief Rodney Noganosh, Chippewas of Rama First Nation: Chief Noganosh began by reiterating the comments of previous speakers that there are many people that are upset with the situation. He also expressed concern that there was not a great deal of time on the agenda for discussion, which was upsetting given that Chiefs travelled far to attend. He noted the need to see results very quickly. First Nations should be exempted from delivery charges. People cannot pay those delivery charges and the communities always have to step in and help. He referred to an economic development project in Barrie and his expectation to receive information on that project so that they would be able to bid on those types of projects. He also expressed interest in learning about the 'blanket agreement' idea, because there has not been much information shared to date.

Ted Snache, Councillor, Chippewas of Rama First Nation: Councillor Snache began by thanking the Elder for the prayer. He noted that if he had a wish, it would be to have elections on the same day to build unity. He expressed the strength in First Nations communities, with young people getting education and women who are water keepers. He expressed that the Ontario Energy Board (OEB) hides behind legalese, but because First Nations are getting educated, that strategy will not work for long. He concluded by asking when the delivery charges will be eliminated for First Nations.

Dave Mowat, Technician, Mississaugas of Scugog: Mr. Mowat notes that the Ontario Energy Board said that if they can focus on the delivery charge, that will have the most impact on the consumer. He would like to know what is going on with that. He also asked what Hydro One is doing about a security plan.

Chief Mary McCue-King, Beausoleil First Nation: Chief McCue-King suggests that First Nations should not be talking to Hydro One because it is not the organization that sets the rates. Hydro One only makes a submission to the Ontario Energy Board; therefore, First Nations should be talking to the Ontario Energy Board before they approve the rates. The Ontario Energy Board should be consulting with First Nations.

Chief [Name Not Heard]: The Chief shared the belief of the previous speaker that First Nations are meeting with the wrong people. The Chief asked now that Hydro One has heard their concerns, what do they propose as the fix? He expressed frustration based on the belief that there are no decision-makers attending the meeting and there will therefore be no deliverables from the meeting. He would like to know the next steps? When can First Nations expect action?

Chief Kevin Tangie, Brunswick House First Nation: Chief Tangie noted that his community experiences the same issues identified by previous speakers and wants to hear answers, solutions and ideas.

Jason Batise, Executive Director, Wabun Treaty Council: Mr. Batise echoed the comments of previous speakers and shared a desire to hear practical solutions. He notes that a First Nations hydro rate was committed to, but that there is no mention of that and the elimination of the delivery charges in the Hydro One submission. He expressed that they had given practical solutions in earlier engagement sessions and they are not reflected in the submission.

Warren Lister, Vice President, Customer Care, Hydro One: Mr. Lister introduced himself as a new member of the Hydro One team and shared his commitment to changing the way they do business. He stated that he intended to listen and welcomed the opportunity to dialogue.

John Onabigon, Councillor, Long Lake No.58 First Nation: Councillor Onabigon shared that he was trying to get resource development for his community. He recounted that in the 1930s and 1940s; Hydro One built their dam and flooded his traditional territory without any regard for the impact on the community. However, he noted that the voice of his people is getting stronger and it is not acceptable that others get the benefits from resources taken from the land of his people. He stated that there is only one square mile left for his reserve and the rest has been flooded. There are many grievances and his people live below the poverty line. He stated that the message from his community has been consistent for years: that there must be a balance of sharing. In his community there is a high level of dependence on Ontario Works and the unemployment level is 85%. He sees this as a game or cycle with people dependent on Ontario Works who pay their excessively high Hydro One bills to keep the lights on to the detriment of other things. Hydro One never feels the pain, but the First Nations do. He notes that his community maintains and asserts the right to their own resources; yet have to battle to get any benefits from them. He then asked why some have so much and some have so little? He also mentions that First Nations are overwhelmed with engagements, and yet nothing has changed for his people. He has seen nothing change over 25 years of doing this work. He added that talking about procurement sounds good but communities do not even have the capacity to be a part of procurement processes.

Cesar Martinez, Customer Care at Hydro One: Mr. Martinez mentions the tools that were brought to the meeting today and encourages participants to bring them to the communities.

Sarah Bruggeman, S. Burnett and Associates Ltd.: Ms. Bruggeman is participating as she is working with a community on an energy plan.

Lisa Johnson, S. Burnett and Associates Ltd.: Ms. Johnson works with Ms. Bruggeman.

Cynthia Jamieson, Executive Director, Mississaugas of the New Credit First Nation: Ms. Jamieson expressed some confusion over the process. She notes that they were expecting a letter from the Minister of Energy to the Ontario Energy Board to hold those sessions. She wonders if that is what this meeting was about. She notes that there were already engagement sessions last fall and wonders if those participants wasted their time. She was seeking clarity on the process.

Chief Tom Bressette, Kettle and Stony Point First Nation: Chief Bressette wanted to add to his earlier statement. He notes that Hydro One is being talked about related to the Bruce Nuclear Power Plant, and burying nuclear waste near the Great Lakes. He was astounded that the Canadian government would consider burying nuclear waste near the Great Lakes. Related to the North America Free Trade Agreement (NAFTA), he notes that First Nations better not be left out of the next rounds. He again expressed disappointment that Hydro One considered that waste facility near the Great Lakes and asked, when it cracks where are we going to get more water?

Chief Simon Fobister, Grassy Narrows First Nation: Chief Fobister described being born and raised on the trap line, where there was no hydro and they carried water. They did not need those things. He was elected Chief in 1976, when he was 21. At that time his community members spoke about a time when water was so clear, but then people came in exploring for hydroelectricity. Now you cannot even see your hand in the water around his community. His community did receive compensation. In Grassy Narrows, hydro bills are high, around $1,000 a month. He notes the need to find ways to cut those rates. He attended the meeting to hear Hydro One tell him their plans to cut the rates. He expressed concern that 60% of hydro comes from nuclear power. Like it or not, the nuclear waste will be buried, and the question is whose backyard will that be in?

Introductory Remarks from Hydro One

Presentation from Mr. Mayo Schmidt, President and CEO, Hydro One

Mr. Schmidt expressed a warm welcome to all of the attendees who committed their precious time. He noted the importance of this engagement for Hydro One. He also provided a warm thank you to Elder Wesley, acknowledged the Mississaugas of New Credit and thanked Chief Niganobe for the welcome.

Mr. Schmidt noted that the work that he does at Hydro One is not the kind of work he has traditionally been involved in. He grew up on a farm and his life's work has been in agriculture. He was approached to work at Hydro One from the prairies and worked to identify a leadership team that could effect change. There was not one Hydro One leader in attendance that does intend to commit to change.

Mr. Schmidt lists three (3) things he is hopeful will come out of this session:

1. To listen and learn;
2. Provide some education on who is responsible for what, what we each do, how can we as a company can to advocate for you and your community; and,
3. Commit to action. The hope is to move this conversation to an outcome (educate/advocate/action).

Background: There are a lot of names out there with involvement in this area. The producer of the power is Ontario Power Generation, which also owns Bruce Nuclear Generating Stations, but leased them to Bruce Power. The Ontario Energy Board approves the rates that Hydro One charges to operate and maintain Hydro One's transmission and distribution systems and sets the price of power. Independent Electricity Systems Operator is responsible for real time operations – the ebbs and flows of power and where electricity goes or comes from.

Hydro One collects from customers for the cost of power (electricity price), and delivery of the power, and delivers the bill. The name Hydro One is on all bills. While Hydro One is the party that bills the party that bills the consumer, the electricity pricing comes from someone else, and Hydro One passes those revenues on.

Hydro One recognizes that they need to address their costs and get them down, and apply to have costs reduced. They also have to do their part to ensure that there are no brown-outs or power outages.

Mr. Schmidt suggests that the feedback that they get from the engagement sessions will go into their upcoming distribution rates submission to the OEB. The information will be collected as part of the application and the First Nations participants' voices will be heard there.

Hydro One is transitioning with a new leadership team with a purpose to put customers first. Hydro One is a publicly listed company with lots of opportunity but everyone must act together. In this there is a need to build and maintain relationships with First Nation communities. Hydro One serves 88 First Nation communities.

Mr. Schmidt recognized that consultation is a protected right and First Nations have a unique cultural relationship with the land. While First Nations are not the only customers, they do have a special relationship. The rising cost of electricity is a concern for all of us, so we will redouble our efforts.

In terms of how billing is structured, 51% of the costs that consumers pay comes from nuclear, hydroelectric, wind or solar producers (will fluctuate, but this is the average), 12% sales taxes and 37% is payable to Hydro One for delivery of power through the network of wires, poles and transmission stations. There is a cost to maintaining this infrastructure, and as an example, Mr. Schmidt mentioned the example of a recent transformer fire, where in replacing that asset, Hydro One recognized that it was built in 1962, so there is a need for continual maintenance of aging assets.

On the question of how do we keep the costs down, Hydro One intends to have a customer presence in local offices; the customer bill was redesigned because customers need to understand the bills; Hydro One has reinforced the commitment to service and of responding in a timely manner.

There was a recent meeting with the province to talk about the cost of power where Hydro One advocated for lower power costs; Hydro One had also proposed to the Ontario Energy Board that the delivery charge to First Nations be lowered as part of the First Nations rate being studied by the Minister.

Hydro One has met with many First Nations over the last 8 years, including over 200 community visits. Mr. Schmidt suggested that communities interested in inviting Hydro One to visit, attendees should introduce themselves to Ms. Cameron and she will get a team out there.

The Hydro One First Nations and Métis Relations team demonstrates an appreciation for the concerns of First Nations communities. They want your feedback on how that works.

Hydro One is committed to making a change as demonstrated by offering additional regional outreach on procurement, by participating in First Nations employment, training and career fairs and through the First Nations Conservation Program.

Mr. Schmidt notes that Hydro One has come far with communities and individuals, by taking issues and solving them one-on-one. If session participants are looking for that attention, then Hydro One is willing to work with them.

Question from the audience: How about eliminating the reconnection fee?

- Mr. Schmidt responded that it costs Hydro One money to send trucks out to turn off and turn on power and that there is a better way to do this -- whether it is giving people who need it more time to pay their bills, getting them on to access programs to assist them, and work with Hydro One to provide guidance on these things.

Comment from the audience: A Chief noted that the connection fee is attached to bills in payment of arrears and is a stumbling block for community members.

- **Response:** Mr. Schmidt responded Hydro One launched a new Winter Relief Program to reconnect customers prior to the winter. This was a practice that started in November 2016 and asked participants to let Hydro One know when people are in that situation.
- **Follow up audience comment:** People are paying this now, sometimes two or three times per year.
- **Response**: Mr. Schmidt responded that if a customer is disconnected, they have to take some hardware off after six months and there are costs associated with that.
- **Follow up audience comment:** Hydro One gets all their fees paid.
- **Response:** Mr. Schmidt responded that in the past this might have been the case, but to participate in the Winter Relief Program, Hydro One needs the names on those accounts and there would be no fees. In general, those fees go into maintaining the system.

Mr. Schmidt: Mr. Schmidt noted that it is important for Hydro One to hear from the participants and focus on things that can be changed. He committed to listen, but also committed to meeting again in the future to work on some of the things we want to accomplish together. It will take bold action by all of us to effect change. It is a complicated industry, with complicated pricing. For these reasons Mr. Schmidt encouraged everyone to focus on what is within their power to change and set priorities. Hydro One is accountable to customers including the meeting participants. The team in place is a new team, and Mr. Schmidt encouraged meeting participants to place their trust and work with the team.

Chief Perrault: The Chief shared that last fall he received a call from a community member who had a Hydro One truck at their door ready to disconnect. He went down there and had to drag the guy off the hydro pole and asked him to leave the community or risk his boss getting a call. There is a perception that there is a push to cut people off before the snow flies. He believed this had to be addressed.

Mr. Schmidt**:** Mr. Schmidt shared that he cannot speak to what has happened in the past, but going forward, the focus is on getting people connected rather than disconnected. He also committed to dealing with the issue of cut-offs himself, along with Hydro One legal counsel. The time frames will be addressed, but in general there is no gain for anyone by cutting people off. The larger issue is that we need the cost of power to be reasonable.

Councillor Warren White: Councillor White commented that he has heard many of these promises before from government officials, but respectfully, he will believe it when he sees it. Further, he identifies a fundamental difference between how connections and disconnections are treated. For example, Hydro One is quick to disconnect but is slow to reconnect clients. There is often a long waiting period, even if the bill is paid. Related to procurement, Councillor White recognizes that there are procurement arrangements with some communities, but the only thing he sees by way of procurement opportunities is cutting brush. He thinks there must be more to offer than that. Councillor White noted that while there may be an Ontario-wide Engagement process, there are different issues; the grievances are different in Treaty 3 and therefore he strongly encouraged Hydro One to have more regional-type meetings. In addition, given geography, it is challenging for community representatives to get to meetings in Toronto, for example. Councillor White commented that February and March are stressful months for Elders because of the accumulation of bills that they cannot pay, and they know they will be cut off. Councillor White notes that Hydro One activities constitute a breach of the Treaties (through flooding, etc.). In addition, there is supposed to be a relationship and a partnership that is not yet realized. Councillor White concluded by sharing a personal story related to disconnection. He had an overdue bill of $1,200, and received a disconnection notice. The bill was paid on Friday and yet his power was cut off on Monday. He attempted to demonstrate to Hydro One that the bill was paid, but was told that the payment had not reached Hydro One's bank yet, so the disconnection went ahead. These situations are real.

Mr. Schmidt**:** Mr. Schmidt stated that he agreed with Councillor White, that Hydro One needed to be reasonable and to rethink previous behaviours that were practiced. He notes that there are a lot of attitudes to change throughout the organization and hopes to do better.

Chief Patricia Faries: Reflecting on Mr. Schmidt's previous comment about constitutionally protected rights, Chief Faries affirms that this is an important point to set the context. She stated unequivocally that the engagement is in no way to be considered consultation and accommodation between Hydro One and the Moose Cree First Nation. She emphasizes that action is key, and she wants a definitive answer on how to move forward. There are power lines going through her land that are intrusive. She expected a response on how her community would be engaged and compensated.

Mr. Schmidt**:** Mr. Schmidt assured participants that the engagement session was not consultation and they did not view it as such. Related to engagement and compensation at a community-level, Mr. Schmidt introduced Jamie Scarlett and Gary Schneider who can sit and meet with communities to work through their issues.

Jamie Scarlett, Hydro One, provided his email address (Jscarlett@hydroone.com) in order to set up future conversations.

Chief Nadjiwon: Chief Nadjiwon sought an update on the discussions around the delivery charge.

Mr. Schmidt**:** It was noted that industry was in conversation with government last week on this issue and discussions are ongoing. Mr. Schmidt notes that Hydro One is advocating for changes related to the delivery charge issue. He invited other Hydro One staff to comment.

Hydro One Representative, Oded Hubert: The Minister has asked the Ontario Energy Board to develop a First Nations rate, and the Ontario Energy Board has prepared a recommendation that has gone back to the Minister for consideration. Chief Ava Hill provided comments on the recommendations and Hydro One supplied data. It is with the Minister now.

Question from the audience: Is there a timeframe for an answer?

Hydro One does not have a time frame at this time, as this is the Minister's initiative.

Comment from Chief [Name Not Heard]: The Chief has attended many meeting over the years, some of which were classified as consultation. The Chief noted that the Hydro One Board of Directors was joining the meeting for dinner, and the CEO is accountable to the board, which gives the organization direction [Mr. Schmidt indicates this is correct]. The Chief commented that having the board at the dinner is fine, but they should have been at the engagement session to hear First Nations' concerns firsthand.

Mr. Schmidt**:** Mr. Schmidt clarified that the Board of Directors does not run the company or specifically direct the CEO. Rather, Mr. Schmidt's team determines a plan, which is presented to the Board for comment. This is different than being instructed by the Board. It is not a decision-making group on an operations level body. In addition, plans that are developed by Hydro One must be approved by the regulator.

Chief Tom Bressette: Chief Bressette suggested that Hydro One must have come up with a proposed First Nations rate, given that they engaged with First Nations last year. He questioned why that rate was not presented to the engagement session. In addition, he felt as though the meeting was centrally about politics. He noted that it may be the same old song and dance and First Nations are growing frustrated without little reason to believe anything has changed.

Mr. Schmidt**:** Mr. Schmidt responded that the reason Hydro One felt that this engagement was important was the need to have a respectful conversation. Hydro One does not set the price of power; however, Hydro One can advocate alongside First Nations to address the price of power. He notes that it comes down to whether or not the participants are prepared to give Hydro One a chance.

Customer Care: Vision, Strategy and Key Initiatives

Presentation from Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One

Mr. Pugliese is the Executive responsible for customer care and Indigenous relations. He noted his appreciation for the openness of the conversation. As the company changes direction from a Crown corporation to a public company, there is an opportunity. The electrical system in Ontario is complicated. In this shift there are three (3) things they have embarked on:

- The first is education, to help explain this complicated system including its regulation, etc. Hydro One has started to uncover what can be addressed and asked for the opportunity to first understand and then work on the things that they can change.
- The second task is related to advocacy. Hydro One owns the hydro bills and holds custody of the relationships with communities and customers. Hydro One has an impactful voice in advocacy similar to the loud voice that First Nations have.
- Mr. Pugliese reiterated that the session was not designed to be a consultation; rather, it was the first step in a series of discussions that will lead to change. He also recognized, like Mr. Schmidt, that change is indeed required, particularly in the area of affordability.

Mr. Pugliese recounted a meeting from the previous week between himself, Mr. Schmidt, the Chair of the Board and Premier Wynne. The Hydro One representatives shared stories similar to those that were heard at this engagement session. He noted that he has been to communities where the distribution charges are more than the power charges themselves and recognized the burden that this places on people like retirees.

He noted that he does not expect the participants to trust Hydro One at its word, but rather, to judge the new Hydro One team on their actions. They committed to visiting First Nations communities, reconnect those who are disconnected, and waive the fees. He asked that the participants let them know which of their community members need this assistance.

Mr. Pugliese recognized, once again, that the primary issue is around affordability, and noted that if Hydro One could control the rates, that the rates would be reduced. However, these changes require advocacy and lobbying. Their conversation with Premier Wynne was for that very purpose.

Mr. Pugliese asked the participants to trust that the information shared at the engagement session would not fall on deaf ears. Some action has been taken such as reconnections and winter relief. Previously, the collection process lacked flexibility and was unforgiving and that has changed. He encouraged participants to speak with Hydro One staff about these issues. The engagement session is one step in a new direction and changes will continue.

Mr. Pugliese left his email address and encouraged participants to hold him accountable to his promises (ferio.pugleise@hydroone.com).

Warren Lister VP Customer Care Hydro One**]:** Hydro One has indicated that they had solutions and ideas to give to the Minister. Many of the short-term solutions that are needed in the communities can be acted on immediately. Hydro One is willing to visit communities that they have not yet visited. For people having difficulty with payments, there can be new payment plans set up. In addition, the winter reconnection program can help get people connected and stay connected. There are still things Hydro One can learn regarding changes that need to be made for communities. The Hydro One staff present were there to answer specific questions and the Minister would be available during the evening dinner. The dinner is an opportunity for both Hydro One and First Nations to use their strong voices for change.

Grand Chief Gordon Peters: Grand Chief Peters noted that his organization has been involved in the process for some time beginning in 1989 around the grievance process. Since that time there has been a lot of work done in the communities and grievances were settled. Issues including billing and grievances arose again within the privatization process. The Hydro One customer care was terrible and did nothing to support communities. Grand Chief Peters was pleased to hear that things would be different; however, he warned that expectations are now high. Grand Chief Peters participated in the engagement process in the fall of 2016. He notes that Hydro One should have laid out the plan at that time; that Hydro One was looking at short-term and immediate changes while looking forward to a longer term plan. It needs to be laid out ahead of time and made less complex. First Nations are seeking how to participate effectively.

Warren White, Councillor: Councillor White shared that he met with Premier Wynne recently. He also met with her two years ago and raised the issue of high hydro bills. He took her his hydro bill, which was $4,200 at the time. The Premier has known about this issue for a long time.

Mr. Pugliese reaffirmed Hydro One's commitment and assured the participants that the commitment will be ongoing. He reaffirmed the need for a partnership with First Nations to get the required changes made. That is the reason why they invited the Minister to participate at the dinner, as he is the policy maker that can affect the changes that are needed.

Chief [Name Not Heard]: The Chief described that when a hydro truck pulls up to a house it dehumanizes the residents. He asked that hydro come to the band office first before disconnecting people. In the past, First Nations had the same experience with archaeologists. The Chief also noted that governments had left it to companies to do that engagement themselves, but that can be traumatizing to communities. The Chief asked what Hydro One is prepared to do when the power goes out in order to get people reconnected in a reasonable time.

Mr. Pugliese responded that the situation described by the previous speaker is not how Hydro One wants to do business. He noted that a colleague, Mr. Greg Kiraly, the Chief Operating Officer, would be joining in the afternoon and would like Mr. Kiraly to hear these concerns as well, as he is looking at the operations side of the business. They want to ensure that in the case of outage that restoration occurs in a timely manner.

Councillor Lisa Kooshet: A participant asked for a recap of the new positions within communities. She asked if there were going to be new Hydro One offices and how those would benefit First Nations communities. She notes that she worked for Ontario Hydro in the past and as a single mom, even while working, had a hard time paying the hydro bill. She expressed that this was disheartening.

Mr. Pugliese noted that Hydro One has launched "Get Local" and written letters to all customers. They are in the process of re-establishing regional or community business offices. They are currently building plans to reinstate regional/community offices to resolve customer issues. In addition, Hydro One is putting a great deal more emphasis on Indigenous Affairs and building more of a strategy around that builds on the good work of Mr. Cameron. This engagement session is the beginning of how Hydro One wants to move forward in doing business. They want to go to the community and regional level on a regular basis.

Distribution Rate Filing (2018-2022)

Presentation by Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One [Distribution Rate PowerPoint]

Mr. Hubert began by explaining what a Distribution Rate Filing means, which is a submission that seeks Ontario Energy Board approval of distribution rates for a five-year period [2018-2022]. The application has not gone in yet, but Hydro One is currently preparing the application and is planning to file at the end of March, 2017.

Hydro One conducted many customer engagements, including 300 First Nations customers, in developing the application. However, Hydro One is still seeking input, and this engagement is a good opportunity to inform the submission.

The distribution rate will apply to all Hydro One customers. There has been discussion on a First Nations rate; there is a request from the Minister of Energy to the Ontario Energy Board to develop an on-reserve rate or rate mitigation for reserves. The Ontario Energy Board responded that they would work on that and in doing so consulted both with Hydro One and First Nations representatives.

Question from the audience: Why is there a discussion on something that is not complete? The commentator shared the worry that this is creating false expectations.

- Mr. Hubert responded that the discussion was taking place in order to hear back on what they are proposing as part of the distribution rate filing, before the Company submits it, so that the input can be included in the Application.

Question from Chief Rick Allen, Constance Lake First Nation: Chief Allen wondered as to the extent of First Nations input on the plan?

- Mr. Hubert responded that there has been some First Nations customer input.
- Mr. Hubert clarified that there are three different initiatives underway, which is leading to some confusion,
- The proposal by Hydro One to the Ontario Energy Board is an Application for distribution rates for the next 5 years.
- There is also working underway on a First Nations rate, which is being reviewed by the Minister.
- The other issue of hydro affordability is one for all customers, and especially for rural customers in Ontario, and this issue is being examined by the Premier .
- Hydro One is here to seek feedback on the first item, the proposed Distribution Rates Application.

Comment from Chief Bressette: Chief Bressette commented that in areas where there are wind turbines, First Nations people could not hunt. This is a violation of Treaty rights. They have found that there are very sudden restrictions based on hydro applications to the Ontario Energy Board.

- Mr. Hubert provided an overview of the generation, transmission and distribution system that serves industrial/residential/commercial customers. Related to Chief Bressette's question, Mr. Hubert notes that Hydro One's only role is to connect generators to the system. Hydro One does not have anything to do with land rights for generating facilities.
- **Chief Bressette:** Chief Bressette responded that First Nations own the land and expressed frustration at the common narrative that First Nations do not own the land and that Canada has rights to the land and resources. First Nations do not beg for "help"; rather, First Nations have a right to benefit from the resources drawn from First Nations land.

Question from Chief Allen: Chief Allen asked why Hydro One is talking about a specific distribution rate for First Nations. Given what Hydro One heard form participants already, why would there even be a distribution cost for First Nations.

- Mr. Hubert responded that Hydro One is not in a position to simply tell the Ontario Energy Board that First Nations will not be charged anything for distribution; however, there is an opportunity to do something, and Hydro One has made some recommendations to inform the OEB's review of the First Nations Rate. The Minister mentioned a First Nations rate or rate mitigation and asked the OEB to prepare a

recommendation. At the same time, Hydro One is preparing for an Distribution Rates application that applies to all customers. It is up to the Ontario Energy Board to approve it or not. In addition, the Minister may be able to make changes related to a First Nations rate, but that decision is with the Minister alone.
- **Chief Allen:** The Chief pushed back on the idea that Hydro One is still applying a distribution charge to First Nations and he recommended that Hydro One just tell the Ontario Energy Board that they are eliminating the charge for First Nations.
- Mr. Hubert noted that they are working on this as part of Hydro One's advocacy role around the rates for First Nations customers and affordability issues in general. They have asked the Ontario Energy Board to adjust the distribution charge.

Comment from Chief Bressette: Chief Bressette noted that the Ontario Energy Board has never invited First Nations to discuss this issue with them.
- Mr. Hubert noted that he believed that the Ontario Energy Board spoke with First Nations representatives about the First Nations Rate Report, but he was not aware of who was involved on behalf of the First Nations.
- **Chief Bressette:** Chief Bressette reminded the room that there is more than one Chief in Ontario and more than one First Nations provincial/territorial organization as well.
- Mr. Hubert stated he was not entirely sure about the Ontario Energy Board process.
- **Chief Bressette:** The Chief noted that the Ontario Energy Board gives other groups a lot of authority over First Nations land without the involvement from First Nations. It is very powerful as evidenced by breaking up Ontario Hydro and making changes without speaking to First Nations. He reiterates that First Nations own the land and are not reported to at all. He states that this way of operating has to change.
- In response, Mr. Hubert notes that forums such as this are intended to drive change. He also committed to finding out about the Ontario Energy Board process when it comes to the discussions that the OEB held on the First Nations Rate.
- **Chief Bressette:** The Chief reiterated that the Ontario Energy Board should be talking to First Nations; OEB should talk to First Nations.

Question from Amy Lickers: Ms. Lickers, in relation to the information on the PowerPoint, what is the difference between the transmission and distribution area in Hydro One
- Mr. Hubert explained that transmission is above 50,000 volts, and typically involves the larger, steel towers and large transformer stations, whereas distribution is below 50,000 volts. He likened the system to the highway and roads systems in the Province.
- **Follow up question from Chief Faries:** Chief Faries asked if that means Moose Factory First Nation were in distribution then, and if that was why the delivery fees are so high.
- Mr. Hubert explained that there is a delivery charge in both, but the majority of the delivery charge is for distribution. Mr. Hubert referred to his PowerPoint [Slide 6] and noted that electricity makes up the majority of the charge. He also committed to provide both hard and electronic copies of the presentation to the attendees.
- **Follow up by Chief Faries:** The Chief asked if it was the Ontario Energy Board who proposed a credit for remote communities. Also, she posed a question to the Chiefs of Ontario, who helped coordinate the engagement session, around whether or not the engagement needed to be with the Ontario Energy Board. In general, what is the

strategy and is meeting with Hydro One the best way to spend our energy. She also asked where Regional Chief Day was.

- Mr. Hubert suggested that the participants were indeed at the right forum and while there were many issues Hydro One cannot deal with, such as nuclear power for example, it is Hydro One who puts together the bill and delivers it to customers. So Hydro One, plays a role in explaining the system to customers. Hydro One proposes rates, but the Ontario Energy Board approves the rates. Mr. Hubert again invited a constructive conversation.

Grand Chief Gord Peters,: Grand Chief Peters noted that it was not Hydro One, but rather the Ontario Energy Board that did the visit last fall, to discuss the First Nations Rate. . He also mentioned again that Chief Ava Hill worked on this and at the time they could not get anyone else to sit on the committee with her. He acknowledged her for taking on that work. He also noted that other people got involved in the process and as that went forward only a handful of other people came to participate. He stated that the participants were there because they had been invited into the process. He did, however, note that Hydro One should have been clearer about what was going to be discussed and the goals of the meeting.

- Mr. Hubert recognized that they were not clear on the invitation that this is a discussion on the Distribution Rates Application by Hydro One, not the First Nations rate; however, they are not a stage where they can give an answer on the First Nations rate, nor are they in a position to do so, as this is the Minister's initiative.

Chief Daniel Miskokomon: Chief Miskokomon noted the need for cultural sensitivity training for Hydro One staff working within First Nations communities.

Councillor Ted Snache: Councillor Snache asked for clarity. From his understanding, power generation was from the Bruce Power plant, and then Hydro One buys the power and then distributes the power. He also noted that Bruce Power makes so much power that they sell it to the United States at a reduced rate.

- Mr. Hubert clarified that Hydro One does not buy the energy; rather they just deliver the power and issue the bills. Hydro One collects the money and then sends it to the Independent Electricity System Operator (IESO, a Crown agency) which then remits it to the power generators. The IESO is responsible for the market and the system operation. Related to shipping power to the United States, the IESO decides at certain times that it is more economical to ship to other jurisdictions at a lower price than to shut down the nuclear plant and start it back up again.

Cynthia Jamieson: Ms. Jamieson asked for additional clarity on the distribution rate application to the Ontario Energy Board. She asked if the three rates were: First Nations rate, regular rate, and an affordability issue.

- Mr. Hubert clarified that there were three independent issues: the First Nations rate, a Hydro One Distribution I rate application, and energy affordability, in general.
- **Follow up question from Ms. Jamieson**: Sought more explanation of the rural rate.
- Mr. Hubert noted that there was a separate discussion going on with government related to energy affordability.

Chief Brian Perrault: Chief Perrault reflected that the primary role of Hydro One is transmission and the business side of energy. He noted that the CEO spoke about trying to support First Nations. He reiterated that the expectation is to get rid of the distribution charge. He wondered why it would be in Hydro One's interest to get rid of that distribution charge. He ended by sharing some cynicism related to Hydro One's commitment to First Nations issues given that it would seem to go against their own business interests.

- Mr. Hubert assured the Chief that these two goals are compatible. He noted that Hydro One needs to collect the total revenues it needs to operate and maintain the distribution system, but rates for different groups could be different, although getting rid of a distribution rate is not an option that Hydro One was looking at. The reduced rate for First Nations, if implemented, will have to be made up somewhere else to fund the business operations.
- **Follow up from Chief Perrault:** The Chief shared that for some homes in his community, the delivery charge is more than half of the bill. He asked what is the percentage of the bill for delivery charge that Hydro One is comfortable with and going to the Ontario Energy Board with.
- Mr. Hubert explained that Hydro One does not have a percentage in mind. When the application is put together, they advise the OEB how much money it takes to run the system, and then developed a budget for five years for the OEB to approve. Once it is approved, Hydro One can recommend different rates for different classes. The Minister can ultimately make that recommendation and adjust through other income sources the rates for other groups..
- **Chief Perrault:** The Chief advised Hydro One against raising the rates of power itself to make up funding from the (potentially lower) distribution rates.
- Mr. Hubert noted that setting the electricity prices was beyond his control but he would not like to see that happen as it would essentially lead to a vicious cycle.

Councillor John Onabigon: Councillor Onabigon asked Hydro One to define a First Nations customer. Is it only on reserve? He noted that First Nations maintain the same rights no matter where they reside.

- Mr. Hubert noted that the letter from the Minister referred to exploring a rate for First Nations on reserve only.

Chief Rick Allen: Chief Allen asked who was involved in developing the First Nations rate. Was it the Chiefs of Ontario?

- Mr. Hubert responded that ultimately it is in the hands of the Minister however, there was an earlier discussion run by the Ontario Energy Board that did not involve Hydro One.
- **Chief Allen followed up:** The Chief asked Mr. Hubert if he knew who ran it.
- Mr. Hubert reiterated that the process was the OEB's and he did not know much more than that about the discussions that the OEB with First Nations. He then further explained the distribution system map in the PowerPoint [slide 4]. He noted that some First Nations are also serviced by Hydro One Remotes who have their own rates, separate from the Hydro One Distribution rates.
- Mr. Hubert elaborated on how the Hydro One distribution charges are spent: preventing outages (47%); upgrading the system (21%); customer service (12%); responding to power outages (10%) [Slide 7].

Chief Reginald Niganobe: Chief Niganobe stated that he participated in one of the sessions between the OEB and the Chiefs of Ontario. He shared a concern noted by an earlier speaker related to off reserve First Nations people. He noted that First Nations know who the members of their communities are. He concluded by asking Hydro One officials if there would be an opportunity to work towards considering off reserve First Nations for the special rate as well.

- Mr. Hubert stated that Hydro One is open to hearing that idea and, in fact, this was the kind of feedback they were hoping to get from this session. He hopes to find a way to work together on issues.

Councillor Skied: Councillor Skied asked about the loss ratio, how the loss is calculated and why customers are burdened with that loss [Slide 6].

- Mr. Hubert explained that line loss represents 4% of electricity costs to customers. He notes that line loss is an expenditure for Hydro One and has to be paid for by someone. The electricity generator produced it, but some of the power is lost as heat during delivery on the distribution system, and the losses have to be paid by someone. He noted that he understand the frustration over end users paying for something they did not get, so Hydro One is always trying to minimize those losses and costs.

Grand Chief Gord Peters: Related to First Nations people in urban areas, distribution charges go down in areas of higher density. He suggested that these reforms could be made in phases; first address First Nations on reserve and then move to urban areas.

- Mr. Hubert restated that the letter from the Minister only mentioned an on reserve rate or mitigation.

Chief Tom Bressette: Chief Bressette sees the on-reserve/off-reserve issue as an attempt to divide First Nations rights. He notes that those living off reserve have never given up their rights. It is called the principle of portability of rights. First Nations were never to be locked on to a little piece of land forever. The OEB should have an answer to the on-reserve/off-reserve issue. It is about Treaty rights and human rights. Canada recognizes human rights. The Chief reiterated that people who live off reserve have portability of rights and can come and go as they please in their own territory.

Councillor John Onabigon: Councillor Onabigon shared that if there are different rates for on and off reserve people it will mean that his Chief and Council will have to discriminate against their own people; however, they were elected by all of the First Nations membership no matter where they reside.

Chief Leslee White-Eye: Chief White-Eye inquired about the cost structure; specifically, what charges the OEB approves for Hydro One.

- Mr. Hubert clarified that Hydro One was responsible for operating the Transmission and Distribution systems. Further, IESO gets a small part of that bill as well.
- **Follow up from Chief White-Eye:** The Chief asked if there was a transportation levy to enter her community, the operating system is where it would fall?
- Mr. Hubert sought clarity on the question. Was the Chief asking who would pay a levy set by a community?
- **Chief White-Eye:** The Chief asked if a company would have to pay a levy.

- Karen Taylor, Hydro One, responded that there is sometimes a charge from communities for access and the presence of Hydro One facilities. This is included in the distribution portion of the bill and is also included as part of the company's revenue requirements.
- **Chief White-Eye:** The Chief asked if that is from the First Nation or the OEB.
- Ms. Taylor clarified that when Hydro One sets the rates they add up all of the costs and it is passed on within the rate. Any fees paid to First Nations for access are passed on through customer bills.

  Chief White-Eye: The Chief suggests that those costs should be passed on to the distributors and generators.

  Gary Schneider, Hydro One, clarified that Hydro One pays for land use, for the value of land and also payment in lieu of property taxes. He noted that they might be able to make unique payments to First Nations, depending on the situation.

Chief Mary McCue-King: The Chief expressed surprise to hear that the year-end amount was $6.5B with costs of $1.1B. There is quite a lot of profit, so she expressed frustration of being told Hydro One cannot afford to lower rates.

- Mr. Hubert noted that the proposed rate increases within the five year application does not take into account a First Nations rate yet. He notes that the majority of the increases are due to the costs of maintaining infrastructure and upgrades.
- **Chief McCue-King:** The Chief noted that in the annual report ending in 2015, Hydro One's debt to capital ratio was 50%. She stated that Hydro One could afford to lower rates as they profited $620M in net earnings. She stated that she listened to what everyone is saying and that Hydro One can afford to eliminate the delivery rate for First Nations communities or both that and profit sharing on the transmission lines going through our communities.
- Mr. Hubert responded that Hydro One had an 8.87% Return on Equity allowed by the OEB, which is the profit and that we are allowed to earn, but if we significantly exceed it we can return some of it to customers as part of the Hydro One's Earning Sharing proposal.

Chief Tom Bressette: Chief Bressette reminded Hydro One that they do not own the land neither does Canada, Ontario or the Ontario Energy Board. Yet Hydro One is taxing it. He wondered what the First Nations' portion of those profits is.

- Mr. Hubert responded that this is a broader question.
- **Follow up from Chief Bressette:** The Chief reiterated that Hydro One is taxing First Nations and he wanted to know where the First Nations' share is. He noted that Hydro One and First Nations are partners. The land is First Nations land, and First Nations people are generous to share it and help non-Indigenous people on these lands. First Nations did their part of fairness and goodness within a partnership and are asking for their half in return.
- Mr. Hubert suggested that the issue of partnership is a broad question. There are some partnerships developed with First Nations already and he hoped that more discussions on partnerships come out of the engagement session.

Councillor Ted Snache: Councillor Snache asked about the potential for breaks related to peak time rates.

- Mr. Hubert said that related to peak rates, this is a challenge because those rates are determined by the OEB. Therefore, any adjustment would have to be explored with the OEB. The Hydro One recommendation was a limited to a change in the delivery charge.

Councillor Warren White: Referring to the Ontario map in the PowerPoint presentation, Councillor White noted that he is a Treaty person, as part of Treaty 3. He asked the Hydro One team if they are willing to honour and respect the Treaty 3 Sacred Law. He asked if Hydro One knows the Sacred Law, or Treaty 3 Resource Law? He suggests that Hydro One needs to learn First Nations laws within Treaty 3. He noted that it is a land base of 55,000 square miles. Hydro One does not have a territory. He notes that education is an important part of any partnership and within regional engagements, and that Chiefs should be educating Hydro One about First Nations resource laws. With this in mind, Councillor White recommended changing the PowerPoint slide with the map of Ontario, which refer to Hydro One's Service Territory, because Hydro One does not have a territory.

Councillor [Name Unknown]: The Councillor wondered if Hydro One staff could explain rate classes. In addition the Councillor mentioned that there are seasonal customers and wonders why they cannot have their own class.

- Mr. Hubert said that in regards to rate classes, when Hydro One applies to the OEB, they develop proposals for specific rates including: urban, two rates for rural, seasonal, and commercial/industrial. He notes that they could also add a First Nations rate. These rates are based on the cost of the assets that serve them. A proposed rate that is not cost-based is therefore a policy decision of the Government and the OEB and is not an arbitrary process.

System Investments

Presentation by Mr. Greg Kiraly, Chief Operating Officer, Hydro One

Mr. Greg Kiraly provided personal background information. He is in charge of operations and is responsible for the Transmission and Distribution System (T&D system) along with Mike Penstone, Vice President of Planning, and Gary Schneider, Vice President of Shared Services.
In his role, Mr. Kiraly is responsible for safety and reliability of the system (including the number of outages and duration of outages). He noted that his job is also to keep costs low or lower costs. This essentially means trying to improve productivity and decrease costs, decrease vendor costs. Essentially, his aim is to keep the system safe, reliable and affordable.

Mr. Kiraly also acknowledged that he does not know much about First Nations and this has been an education for him. He noted that his job is to achieve operational excellence. To identify where Hydro One is at, identify where they can get to and to put a plan into place to get Hydro One there.

Representative from the Chippewas of Rama [No Name Provided]: The speaker questioned what Mr. Kiraly's presentation has to do with hydro rates. They noted that they had to cancel some important meetings to attend this engagement session.

- Mr. Kiraly responded that he will get to a discussion about reliability and how that affects everyone within the system.

- Referring to the PowerPoint [slide 8] he noted that within the transmission system the primary causes of interruptions is equipment failure and weather. Other causes are major environmental events (tornados, fires, etc.) and animal/vehicle/tree contacts.

Chief Patricia Faries: Referring to Slide 9, she noted the green dots, which indicate issues with reliability. She wondered why there were no lines identified on the slide in those areas.

- Mike Penstone, Vice President of Planning, Hydro One, explained that not all Hydro One lines are represented on the map as it would be too cluttered. He noted that they are monitoring those lines within the distribution system where there are system disruptions. Where Hydro One sees deterioration or degradation, there will need to be repairs and costs associated with those improvements.
- Mr. Kiraly added that it costs more in northern and remote areas to service the system.

Chief Gerry Duquette Jr.: The Chief suggested this is just a reality in Canada. Further, he noted that his community was not represented by a dot on the map within the slide.

- Mr. Penstone clarified that the dots represent hydro stations, not communities.
- **Follow up from Chief Duquette:** The Chief noted that his community had created their own energy project, where the band paid for the line in the 1950s. He suggested that it is discouraging when he hears about the costs. He also suggested that Hydro One should provide their employees a lunch box as many times they are working close to restaurants and so once they leave to get lunch, it takes a long time and things do not get done. In his community they had outages for 11 days; also during Christmas time. Chief Duquette suggests that he is looking forward to change and that his community has been asking what was going to happen. He needs to take the information back and share it with his community.
- Mr. Kiraly responded that Hydro One does not rest until every customer has their power back on but recognizes that it is more challenging in the remote north.

Chief Melvin Hardy: The Chief suggested that Hydro One look at repairing the transmission lines around Lake Nipigon. There is a station near his community and there is still trouble. He also asked a question around when the lines break and are repaired, would the rates go up.

- Mr. Penstone responded that, in order to ensure transmission networks provide reliable service, investments need to be made. He notes that Hydro One is spending money to sustain its networks and those investments are recovered through hydro rates.
- **Follow up from Chief Hardy:** The Chief asked that if it breaks do customers pay for it?
- Mr. Penstone responded that Hydro one anticipates that there will be repairs and costs
- **Chief Hardy:** Responds by saying that there are lots of hours with power and when Hydro One equipment fails, do customers pay for it?
- Mr. Penstone answers that, yes, but all rate payers pay for the repairs.
- **Chief Hardy**: Notes that there is greater density in the south and thus they have lower rates. He noted that Hydro One should have some statistics that are First Nations specific.

Mr. Kiraly noted that Hydro One is looking at getting coverage around the clock and is working with the unions on that. He notes that they have good reliability on the transmission system but less so on the distribution system as it does not have the same technology. Mr. Kiraly notes that

Hydro One workers sometimes have to check an entire line; that could be 100 miles long. Hydro One needs to upgrade this to avoid these delays. These upgrades will take years of investment and changing labour agreements, all aimed at improving reliability.

Chief Brian Perrault: The Chief recounts an incident last spring where there was a Hydro One crew in his community clearing trees around the lines. The crew came right into his yard where he had 5 trees. Instead of trimming the trees, they cut them all down. The Chief's wife's grandfather planted those trees and he felt like he should have been spoken to about it before they were cut.

- Mr. Penstone said that Hydro One has not trimmed in a long time. There are OEB standards related to dying and diseased trees. However, Mr. Penstone felt that he could not comment any further because he did not know about the specific situation. In addition, he committed to following up.

Councilor Ted Snache: Councillor Snache noted that the cost saving measures were part of what Hydro One does and it makes sense to redo the lines as quickly as possible.

- Mr. Kiraly noted that it is about balance. That Hydro One can ask the OEB to make these kinds of investments that are needed, but if we ask for that there needs to be an increase in the rates.

Chief Mary McCue-King: The Chief noted that there were issues with the lines in her area and asked if this is that going to impact the hydro rates in her community. She noted that Hydro One had proposed a change from a single phase to three phase power. She wonders if that is necessary and if it were more expensive.

- Mr. Kiraly responded that it would be more expensive. What you are talking about is a submarine cable and the cost would be borne by all rate-payers. Referring to slide 10, Mr. Kiraly describes the line performance for First Nations in 2016.

Chief Leslee White-Eyes: The Chief thanked the presenters and noted that the information was helpful. She was wondering about the relationship to community emergency planning. Specifically, she asked if Hydro One develops relationships in the community or is it more reactive. For example, can there be collaborative work to develop poles that have street lights on them. In this, Hydro One would be giving back to the community. She asks if there are other details of potential relationships going forward including sponsorships, career fairs, developing community protocols for when Hydro One comes into First Nations.

- Mr. Kiraly responded that Hydro One is open to any of the ideas the Chief just mentioned.
- Mr. Penstone said that related to the street lights, there is a legacy of sentinel lighting, but Hydro One is open to any suggestions.
- Mr. Kiraly mentioned that related to emergency planning, there are some relationships with communities around that, but he recognized that there is certainly not enough of that going on. He continued that they are open to any protocol that the Chiefs feel is most appropriate, for example, Hydro One workers stopping at the band office to let the leadership know what is going on. Mr. Kiraly concluded by saying that many of the items that Chief White-Eye mentioned were possible to achieve.

WRAP UP

Mr. Goulais indicated that as heard from the participants, Hydro One should be providing the wrap-up.

Mr. Ferio Pugliese, Executive VP, Customer Care and Corporate Affairs, Hydro One, began by thanking Mr. Goulais and calling up the Hydro One Executive Team to the front. He noted that the conversations were captured visually and in notes. He reminds participants that these are the beginning of more discussions in order to lead to action. Mr. Pugliese identifies the main themes of the discussion.

1. The short-term, immediate economic issues including affordability: There is the additional rural burden and hefty delivery charges. There needs to be serious attention paid to the economic realities faced by First Nations and identify how to provide relief.
2. The need for policy change: A First Nations rate is beyond the power of Hydro One to change, but the Minister will be attending the dinner and may have more insight into the First Nations rate.
3. Longer term issues: There is a need to address longer term issues including outstanding agreements around access, rights, land use, assets on the land. There have been fruitful agreements in the past and Hydro One will continue to work on agreements with First Nations.
4. Relationships and Engagement: Hydro One needs to work with First Nations to develop a long term strategy on engagement. This was the first of many meetings. Hydro One is willing to come to your communities, regions, and tribal councils. These are opportunities to share information and educate both ways.

Mr. Jamie Scarlett, Executive Vice President, Chief Legal Officer, Hydro One, noted that the executive team members see working with First Nations as an overlapping mandate across their areas of focus. He noted that they understand it is critical to deal with costs and rates and Hydro One needs help from the government on that. Senior management understands how acute the issue is for First Nations. Regarding land use and resources, the team learned about how long negotiations have gone on and how this has been unacceptable for First Nations. They do not want these kinds of delays to continue. In order to achieve this, he encouraged direct, open and energized conversations. He encouraged a principled and fact-based method of moving forward. Thirdly, he noted the need to move forward on partnerships and co-ventures and working with First Nations more in the area of procurement.

Mr. Greg Kiraly, Chief Operating Officer, Hydro One, expressed gratitude for being at the engagement session. He thanked the crowd for good questions, comments and providing an education for him. He also noted that the participants could count on him and his team to improve the reliability of the system and get costs under control.

Mr. Pugliese asked for any questions or final comments?

Councillor Ted Williams: Councillor Williams shared an appreciation for the meeting and noted that he learned a few things. He stated that it was a difficult day and he appreciates that Hydro One heard their community issues. He noted that he does not want to come back in a year with nothing changed for the better regarding power. He commended the senior officials for facing a tough crowd.

Mr. Pugliese noted that he wants to be back here celebrating success in one year. The comments will be shared with board members. He concluded by noting that the meeting will end but the conversation will not. He encouraged participants to reach out to Hydro One if there is something you would like to add, and Hydro One will be happy to come to your communities for similar meeting. Thank you.

Meeting Adjourned

Hydro One and First Nations Engagement Session
Mandarin Room, DoubleTree by Hilton
Friday, February 10, 2017

SESSION REPORT

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WELCOME

Mr. Phil Goulais, Session Facilitator, called the meeting to order and introduced Elder Andrew Wesley. Elder Wesley provided the opening prayer and a smudge. Mr. Goulais noted that on the previous day, the session was welcomed by the Mississaugas of New Credit First Nation and he thanked them for continuing to allow the attendees to meet on their territory.

Mr. Goulais provided background information from the previous day and thanked participants for letting him share the day with them. He noted that he was pleased to see his own Chief present, Chief McLeod. In his work with Hydro One, Mr. Goulais has built relationships with communities and has travelled to communities to give procurement workshops and share career opportunities at Hydro One. He noted that Chiefs were asking how to work with Hydro One and effect change, particularly around hydro rates. At the same time, Hydro One was asking how to work with First Nations. This came from an understanding of the need to work better together. This was part of the motivation for hosting the engagement session.

Mr. Goulais shared the message from the invitation related to the objective of the session: "*Our most important objective is to hear from you and the issues that matter to your community. We will also be pleased to share our current thinking and solicit feedback on the application for Distribution Rates and the distribution system plan that we are preparing for submission to the Ontario Energy Board.*" He reassured participants that these discussions did not constitute consultation, and that it was just meant as a discussion. He noted that it was an honour to work with the Chiefs and Councillors, Grand Chiefs, Deputy Grand Chiefs and the Regional Chief. It was an honour to hear firsthand what community members are saying.

Mr. Goulais noted three senior executives from Hydro One in the room, noting that they are the decision-makers and the engagement is an opportunity to draw from their experience and knowledge. They were attending to hear the views of First Nations. He concluded by stating that the engagement is an important first step. He commended the participants for venturing out and taking that step. He shares his hope for a productive day of information sharing and discussion as well as establishing a plan going forward to continue the discussions and strengthen the relationship further. He asks that everyone consider what they will collectively leave as a legacy for their young people and generations to come.

As far as the morning's agenda, Mr. Goulais asked that participants introduce themselves, state where they are from and any early comments. Mr. Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs will give a presentation on customer service. He asked participants to speak to what they would like to get out of the session, and what great customer service means to them. It was noted that notes of the meeting are being taken and participants would receive the written notes of the session for review. In addition, a graphic artist is capturing comments in a graphic way.

INTRODUCTIONS

Chief Barron King, Moose Deer Point First Nation: Personal Introduction

Jerry Fontaine, First Nations and Métis Relations, Hydro One: His work with Hydro One involves travelling to communities and conducting relationship-building work. He is from Treaty 1 in Manitoba, Sagkeeng First Nation. He is also party of Treaty 3, as the treaties did not recognize provincial borders. He noted that at the session yesterday there was some confusion on the point the purpose of the meeting, so he clarified that it is about building a relationship, trying to do things right, and identify where there can be changes at Hydro One. The company is seeking how to do things differently.

George Kakeway, First Nations and Métis Relations, Hydro One: Mr. Kakeway introduced himself as from Rat Portage, Treaty 9. He noted that he works with Treaty 3 communities and has been doing this work for Hydro One for about three years. In doing so he follows the traditional spiritual protocols before entering each community.

Chief Tom Johnson, Seine River First Nation: Chief Johnson noted that in his community when they see a Hydro One truck it is only for one thing [presumably to cut off service]. He notes that it has been a long process of negotiations and he would like to walk out of the engagement session feeling good about the process. He recognized that one day would not solve everything; there will need to be more time. However, he was looking for something to look forward to regarding hydro rates.

Rob Globocki, Director, Customer Service, Hydro One: This Customer Care Director noted the desire to establish connections with customers. They do not want to be seen as just people who come to cut people's power off. He suggests that Hydro One wants to work with First Nations, provide information and ask about First Nations' needs and priorities.

Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One: Mr. Pugliese noted that he has only been with Hydro One for five months. He is originally from Ontario. He describes his responsibility as being about customer care and Indigenous Relations. He thanked the participants for coming and noted that the previous day had been a frank and honest discussion. He suggested that the Hydro One executive team were forging a new commitment to relationship building. He reiterated that Hydro One appreciates the presence of the attendees and recognized that they were busy. He reaffirmed that the session is a conversation and is not a consultation. He saw this as the first chance to meet and get to know the new team and answer participant questions. He also mentioned that they wanted to do more community visits.

Steven Nootchtai, Councillor, Atikameksheng Anishnawbek: Personal introduction.

Chief Alex Batisse, Matachewan First Nation: Chief Batisse noted that he was attending to voice his concerns about the very high delivery rates.

Amy Lickers, Chiefs of Ontario: Ms. Lickers introduced herself and said that she works with the Chiefs of Ontario Chiefs Committee on Energy.

Sherrylyn Sarazin, Councillor, Algonquins of Pikwakanagan: Councillor Sarazin noted that her community has a long-held grievance with the energy sector. Dams took away their food; the eels disappeared. Energy lines were brought through in 1954 without permission. They are only now almost at an agreement. She noted the need for more cross-cultural sensitivity training for the staff dealing with First Nations. They should know the Seven Grandfather Teachings. She wondered how her community members could see relief directly on the bills, given the rising cost of living and high hydro bills with delivery fees costing more than the energy. She is seeking a solution.

Chief William Diabo, Magnetewan First Nation: The Chief noted that he is in his third term in office. He thanked the organizers for putting together the gathering to bring his community's concerns to the table. His concerns are primarily about the relationship, the services and the high rates faced by his community. He noted his hope to achieve a solution, not just hear more words.

Chief Greg Peters, Delaware Nation (Moravian of the Thames): The Chief noted he is in his fifth term in office. He was attending the meeting for similar reasons to everyone: the standard of living for his people is in jeopardy. They have lower standards of living than other communities. To address this, they need to come up with a plan.

Chief Dean Sayers, Batchewana First Nation: Chief Sayers notes that the government of Ontario compels Hydro One to work with First Nations. His Elders make sure he expresses the fact that First Nations in Ontario pay the highest taxes of anyone. They had to give up 50% of their revenues and their quality of life. In the 1800s they were managing the resources but that was taken away. They refused to pay taxes to the government because they already paid with the violations on the land. Any tax that is paid today (PST, GST, etc.) is a violation of their Treaty. He notes that one measure that Ontario could do is point of sale exemptions for all First Nations in Ontario for any tax. If First Nations, no matter where they live, show a status card in paying a Hydro One bill, all taxes should be removed. The delivery charge should also be removed because of the lines going across their lands. Chief Sayers notes that there are many other issues that he would like to bring forward. He thanked Hydro One for inviting him and the other Chiefs for attending as well.

Tausha Esquega, First Nations and Métis Relations Team, Hydro One: Personal introduction.

Cesar Martinez, Customer Care, Hydro One: Mr. Martinez was attending the session to find solutions that are mutually agreeable.

Chief Scott McLeod, Nipissing First Nation: The Chief shared that he was encouraged to hear that Hydro One wants to hear the issues faced by First Nations. The situation is tough. His community just signed a bunch of cheques to help seniors make it through the winter. Most of the homes in his community are heated by electricity, so people have to choose between food and heat. He also echoed the comments from Chief Sayers regarding the constant struggle with the government to honour their Treaty obligations. He notes that hydro is a resource that is taken from the land, and instead of sharing; First Nations have to pay huge costs for it. Energy is generated from Mother Earth, and we have agreed to share it in the Treaties. The Chief hopes he can start seeing the government live up to their obligations.

Kathleen Naponse: Ms. Naponse noted that she is from Whitefish Lake but is attending on behalf of Thessalon First Nation. She would like to know what is happening with the rates and where there are plans for more lines to go. She sees this as impacting her Treaty rights.

Imran Merali, Interim Director, First Nation and Métis Relations, Hydro One: Personal introduction.

Karen Taylor, Senior Director of Regulatory Affairs, Hydro One: Ms. Taylor noted that she worked on the application to the Ontario Energy Board (OEB) and she was also a member of the Ontario Energy Board at one time. From the meeting, she hoped to take away sustainable and actionable items.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte: Chief Maracle described his vast traditional territory that extended to both sides of the river. This territory was never surrendered nor was any of the rights within that territory surrendered. The Niagara Power Generation Station is within that territory and his community is looking for benefits from that. First Nations' resources have led to a comfortable life for the colonizing nation to the detriment of First Nations quality of life. People on reserves are paying the highest rates. These people are further away from big cities, have lower incomes, can only find part-time jobs and often work minimum wage. He notes that the dynamics within the province were not considered in developing the current rates. In addition, municipalities have collected royalties from power lines that cross First Nations land. Sometimes there are land claims or lands that have not been surrendered at all and First Nations should be compensated. He notes that First Nations have contributed resources to the country and have also contributed in times of war. Rates are a political decision, and thus can also be changed by politicians. The rural rate is not properly applied to First Nations. From the meeting, Chief Maracle was looking for some kind of commitment. The OEB will do what the Minister tells it to do. If the Minister was committed to developing a First Nations rate, they should have already had their discussion and told the Chiefs what the decision is. He noted that he hopes this happens. He also hopes that First Nations can build a better working relationship with Hydro One and Ontario, based on the actions that are taken in response to First Nations' concerns.

Art Jacko, Manager of Lands and Resources, Whitefish River First Nation: Mr. Jacko noted that Chief Shining Turtle could not attend, so he was attending in his place, primarily to find out more information. His territory encompasses Treaty 3. None of the promises were ever fulfilled. Fast forward here today, Ontario has created a huge regulated monster. He stated that he was glad to see there is a new management group and will be watching to see how things change. He noted that the process is about the Hydro One application to OEB. He agrees that the infrastructure needs to be addressed. He noted that he knows the cost of running a business however, it is hard to understand and to explain to his people the rationale and reason for the rates that are being contemplated. While there are huge profits at Hydro One, First Nations communities continue to suffer and have not seen any breaks. In the 1853 treaty, First Nations were promised $4 at that time. Today it is still $4. He noted that he looked forward to seeing the application that Hydro One will submit and how they intend to deal with those Treaty issues.

Peter Nahwegahbo, Consultation Officer, Aundeck Omni Kaning First Nation (Sucker Creek): Mr. Nahwegahbo noted that he was attending on behalf of the Chief, and will be taking information back for the Chief. He noted that he was looking forward to this meeting, as it was his first session with Hydro One. He recalled that, 15 years ago, he went to his Chief about his hydro bill and then followed up 10 years ago. The Ombudsman of Ontario is finally hearing his case.

Chief Edward Wawia, Red Rock Indian Band: The Chief noted that 15 years ago his mother was Chief and she was saying the same things being said at this engagement session. His community has three dams in their back yard. They are close to Nipigon and yet their bills are 2 or 3 times higher. He would like an answer for why that is. He explained that they teach their young people to conserve energy and pay their bills, but when their bills are so high and the delivery charge is so high, they have troubles paying. He suggested that the delivery charge is so high because First Nations cannot be taxed. He concludes with a comment on maintaining the hydro lines; he would like to see a manual way of tending the lines and an end to spraying the lines.

Gary Schneider, Vice President of Shared Services, Hydro One: Mr. Schneider explained that procurement and land matters falls under his area of responsibility.

Chief Dwight Sutherland, Takwa Tagamou Nation: Personal introduction.

Peter Archibald, Councillor, Takwa Tagamou Nation: Councillor Archibald cited a number of issues that needed to be discussed with Hydro One. He mentioned a transmission agreement process they are hoping to start and they need to know who to speak with and where to go from here. He reflects that delivery charges are another issue. These charges are sometimes three times the electricity charge. There are also transmission problems despite there being several generating sites in his territory. One was just built at New Post Creek. They have also been impacted by not being able to fish out of their river anymore. There are well-documented impacts of sewage dumping, including damage to the environment, and the animals cannot drink there either. This is not being monitored. They are also impacted by Highway 101 and mining in the area. There was no regulation on these activities prior to the Environmental Assessment process. He shares that there is no doubt that people got sick and died from the contamination. He concludes by inviting Mr. Cesar Martinez to meet with him and discuss these issues further.

Oded Hubert, Vice President, Regulatory Affairs, Hydro One: Mr. Hubert noted that he would be giving a presentation later in the afternoon.

Devi Shantilal, First Nations and Métis Relations, Hydro One: Personal introduction.

Lucy Trudeau, Band Manager, Sheguiandah First Nation: Ms. Trudeau noted that she would like to bring back to her community real world solutions to the many issues they face related to hydro.

Daniel Charbonneau, First Nations and Métis Relations, Hydro One: Personal introduction.

Erin Henderson, Regulatory Affairs, Hydro One: Ms. Henderson noted that she had been working with the First Nations and Métis groups at Hydro One in relation to this session.

Valerie George, Consultation Coordinator, Chippewas of Kettle and Stony Point First Nation: Ms. George noted that she wanted to follow up on a point made earlier by Chief Sayers around transmission lines. She also raised the point around an off-reserve exception because sometimes people have to move off-reserve but that does not mean they have forgone their right. She ended by reminding Hydro One that this is not a consultation and Hydro One was not provided consent for anything.

Chief Paul Eshkakogan, Sagamok Anishnawbek First Nation: The Chief expressed his desire to talk more about solutions and the work that needs to be done to achieve those solutions. He noted that the Premier could impact the rates. He added that there was a need in his community for employment and training. He recalled, years ago, when Hydro One was building the 250kV line from Sudbury to Sault Ste. Marie; they were recruiting community members across the North Shore. He noted that now, we need to go back and look at how First Nations can participate in the business and create employment in his community. He would also like to look at partnering with Hydro One to look at creating energy efficient communities. He notes that there are many energy sources in First Nations that should be considered. He shared that he was looking forward to the discussion.

Warren Lister, Vice President of Customer Care, Hydro One: Mr. Lister explained that his role is everything to do with billing and energy conservation. He noted that they are waiting to hear about rate relief from the Minister, but that in the meantime, Hydro One can do some things to assist First Nations and that is what he was interested in speaking about. He noted that he knows Hydro One has work to do as it relate to policies and procedures and committed to taking action on those.

Chief Wayne Pamajewon, Shawanaga First Nation: The Chief explained that he was attending the session out of a concern for where we are headed and how we get there. He also affirmed the words of Chief Sayers. He notes that the issues with Hydro One have been around for a long time. His community signed an agreement on hydro in 1951, which clearly points out that power would be delivered, to his community and three other communities at no cost. The interpretation of the agreement is not done from the First Nations perspective. His band members are telling him that they cannot pay their hydro bills and have to choose between food, power or rent. He notes that he came from a time where they would study using a coal oil lamp and when they ran out of oil they borrowed or got creative. Today people need power. We must find a way to make it better for his people. He notes the treaty, which begins at the Severn River and goes to Batchewana Bay. Those lands belong to his community and Hydro One has not paid for crossing those lands. That Treaty said that the First Nations would get benefits. This has not happened. According to that Treaty, his people should not be paying for hydro. They have paid enough. The Chief noted that his community needs three-phase power. They have upgraded the lines a little bit in the community but they still have lower electricity costs and very high delivery charges. The Chief had asked his community members to hand in their bills in order to record the total costs his people were facing. He suggested that all the leadership in the room do that. As Chief, in 2012, he sat at a huge table with First Nations on one side and Hydro One lawyers on other. They did not get very far. He questions how Bell Canada can be paying Hydro One for the use of the poles with no agreement from the First Nations. He noted that he wished some Hydro One policy people had to live on the reserves before making policy for First Nations. He concluded by saying he wanted to talk about the future for his community.

Mary Ann Giguere, Councillor, Thessalon First Nation: Councillor Giguere noted that she has concerns about the high hydro costs, and was attending the meeting to take information back to her people.

Chief Patricia Big George, Anishnaabeg of Naongashiing: Chief Big George began by stating her community was part of Treaty 3. Many of the issues that had already been brought up, resonated with her. She described that her community is at the end of Highway 21. She notes that the delivery charges are usually way more than the hydro charges. She asked if anyone sits at a negotiation table with Hydro One. She described a substation about 35 km from her community that was built when a mine came in. She thought that hydro rates would go down, as a result, but they actually went up. She viewed Hydro One as catering to the mine as there is an economic incentive coming from the mine. Regarding procurement, she noted that the only contract work for First Nations seems to be cutting trees around the line. She asked if that was the only work available. She asserted that First Nations are worth more than menial tasks. She noted that about 60% of her community members are taking their hydro bills to the band office because they cannot afford to pay them. They should not have to rely on band funds to pay those astronomical rates.

Chief Lorraine Crane, Slate Falls First Nation: Chief Crane noted that she wanted to come to the meeting to discuss the many issues with Hydro One. She describes being born and raised on the land. Hydro One entered the area in 1930. There were agreements between Hydro One and six bands signed in the 1990s. She notes that they have never received reserve status, partly, she believes, because of Hydro One. They have been fighting for decades. The Chief recalled talking to a woman at Hydro One and the woman said Hydro One held the pen. This was both frustrating and offensive. In addition, her community shares many of the same struggles with Hydro One as others have mentioned. Hydro One can just drive in any time and disconnect people, and the community struggles to get people connected so the pipes do not freeze. The hydro bills are high and there is not a lot of employment in her community. They have annual contracts with Hydro One for clearing the land around the lines. She noted that when she was growing up, she always respected the hydro line going through the land. They always let people go through the land. This adds to her frustration alongside no reserve status, high costs of hydro and Hydro One can just come in whenever they want. She wants this to stop.

Chief Dorothy Towedo, Aroland First Nation: Chief Towedo noted that their concerns were many of the same already stated. She is new as a Chief and is learning. Her community is about four hours from Thunder Bay. They also do not have reserve status. She noted the outrageous cost of hydro while her people live in poverty. It makes it hard to pay for heating in winter. Many in her community are unemployed. Many families are forced to choose between power and food. This is also a challenge for Elders and people on fixed income. They also face challenges with interruptions to power that sometimes last days. As a result food gets spoiled and these are people who cannot afford to waste any food. Many people come to the band office for help with food or the hydro bill. The Chief concluded by stating that she was attending to learn how the system works and how these rates are determined.

Chief Elaine Johnston, Serpent River First Nation: Chief Johnston expressed gratitude for attending the session. She supported the comments of Chief Sayers regarding the Treaties. Her community is part of the Robinson Huron treaty area. The political conversation around 'Canadian Values' from Kellie Leitch reminds her that everyone who came to Canada is an immigrant. She posed the question: what are Canadian values? How did settlers treat First Nations people? She reminded the room that First Nations people treated newcomers well but that was not reciprocated. The way that First Nations have been treated for 500 years has been abysmal. Regarding relationships, the Chief notes that each side has to understand one another. She was pleased for the opportunity to open up a conversation; however, there is a need for some cultural understanding and an understanding of First Nations history, in order to understand where First Nations are coming from. The fathers of confederation gave First Nations people the residential school system. Hydro One needs to know the history of this country. Regarding energy, the Chief noted three things: 1) the Minister of Energy is the one making decisions; 2) there is confusion around Hydro One and the OEB. Who is doing what? and, 3) there needs to be some cultural recognition within Hydro One from the bottom to top. In addition, there needs to be designated staff as part of the call centres that can respond to land issues and taxation issues, etc. The Chief noted that when members call the call centre they get nowhere. Chief Johnston concluded by sharing appreciation to Hydro One for hosting this event because relationships start with dialogue. While Hydro One is sharing information, First Nations should share their perspectives too.

Deborah Wetzel, Councillor, Big Grassy First Nation: Councillor Wetzel concurs with everything previously said.

Lee Anne Cameron, First Nation and Métis Relations, Hydro One: Personal introduction.

Chief Wayne Smith, Naicatchewenin First Nation: Chief Smith noted that it was a pleasure to attend the engagement session. He came hoping to know more about delivery charges, as it is the biggest issue facing his First Nation. He recounted a personal anecdote that was instructive of what his community members deal with related to Hydro One. He shared that he had a rental unit that he paid the hydro for monthly. His tenant moved out in October, so he closed off the account. When a new tenant moved in, he transferred the bill to the new tenant. He received an excellent letter of recommendation from Hydro One, but also received a $126 bill from the month before. He forgot about it and missed the due date by a week and a half. Ultimately he paid the bill online. However, when he came back from vacation it had been sent to collections by Hydro One. The Chief noted that First Nations members are badly treated by Hydro One customer service and there is a real need for a change in attitude. He also agreed with the issues brought up by the other participants. Out of this meeting, the Chief was hoping to learn more about Hydro One and also move from talking to action.

Jason Laronde, Director of Lands and Resources, Union of Ontario Indians: Mr. Laronde shared that he was attending the meeting to listen.

Brendon Huston, Economic Development Coordinator, Union of Ontario Indians: Mr. Huston noted that he was also attending to listen.

Chief Wayne Pamajewon, Shawanaga First Nation: The Chief noted that when it comes to submersible lines, that First Nations never gave up rights to the water.

CUSTOMER CARE

Mr. Ferio Pugliese, Executive Vice President, Customer and Corporate Affairs, Hydro One
Mr. Pugliese began by thanking the participants for the frank discussion and open dialogue. He noted that Hydro One was undergoing a lot of changes, including a new system in Ontario. There are a lot of moving parts. For its part, Hydro One is undergoing profound changes, because of the shift towards a private company with shareholders. Providing some clarity, Mr. Pugliese noted that Hydro One was not in the power generation business, but in the Transmission and Distribution businesses. Hydro One does manage the delivery charges. He admitted that the new team at Hydro One recognizes that things had happened in the past when it came to First Nations land and communities. While they cannot change what happened in the past, the new Hydro One team is making a commitment to work differently, in partnership with First Nations. He asked the attendees to judge the new team on their actions. He noted that in a year from now, or sooner, Hydro One will be able to share insights and progress on closing out past grievances, in helping community members with bills, and making movement on

affordability. He recognized that this meeting was the first step in a long journey of building relationships.

Mr. Pugliese provided information on four points: the First Nations rate, affordability, calls to action, and understanding the distribution rate filing. Regarding the First Nation rate: in Ontario hydro bills are generally made up of the following: 50% for generation costs (nuclear, hydro, gas, wind, solar, biofuel) and 37% of the bills are distribution costs. These costs vary based on density (more poles than people in rural areas). Hydro One applies for, but does not set the distribution rates; those are set by the OEB. However, Hydro One is trying to influence change related to those distribution rates. Mr. Pugliese recalled seeing bills where the delivery charge is larger than the consumption charge. He noted that he views this as a serious problem. He recognized that in remote communities, where there is electrical heat combined with poorly insulated homes (not on gas lines for forced air), the result is high consumption charges plus even higher delivery charges.

Regarding the potential for a First Nations rate; this is an issue being managed by the Minister of Energy. In developing the proposed First Nations rate, there were meetings with the Chiefs of Ontario and five (5) sessions that included 48 communities. The First Nations consultation was completed last fall in 2016. Mr. Pugliese shared that the final paper was filed by the OEB with the Minister on December 29, 2016 and he believes an announcement on the First Nations rate is imminent.

Hydro One does not want those high rates for communities and has teams working on affordability issues. Once those are resolved, then they can move on to system issues. Hydro One has been focused on education, advocacy and responsiveness. The need for education is acute because not many people understand the hydro system in Ontario. Customers, communities and even decision makers/policy makers need to understand the breakdown of costs and why they are so high. There was a cost increase once Ontario got off coal, for example, which was transferred to the cost to consumers. Hydro One can watch its costs, save money in different ways, and defer expenditures, where possible. Hydro One operates on the cost recovery system, and there are costs associated with maintaining that system which requires capital investments. These plans all have to be submitted to OEB.

Mr. Pugliese noted that Hydro One also plays an important role in advocacy that includes going to policy meetings at the Minister's office and also with the OEB. Hydro One met with the Premier last week and presented an advocacy position on behalf of customers. In that meeting, Hydro One described the situation as a crisis that needed radical redesign of policy in order to address the affordability issue. At that meeting, Hydro One shared information on how the redesign might look to reduce costs on the power generation side, etc. Mr. Pugliese noted that it was not just Hydro One who brought this message to the Premier, although Hydro One probably feels the most pressure because their name is on the bill. Hydro One owns that relationship with customers. Hydro One needs to start listening to the impact that high bills are having. The message was well received by the Premier and the level of engagement and knowledge of the Premier and her staff was impressive. Mr. Pugliese commented that Hydro One saw it as time to act as the voice for their customers, but this advocacy is not something that they can do alone. Hydro One believes that the voice of First Nations on this issue is strong. Hydro One and First Nations sharing the same message on affordability would be powerful. Related to improving Hydro One's responsiveness, Mr. Pugliese noted that they have heard First Nations speak about empty promises from the past. The new team at Hydro One will improve on this performance.

Mr. Pugliese notes that there are some actions that are beyond their ability to change, however, where they can; there are some actions that can be taken to respond to First Nations concerns. Recently they have taken some steps such as waiving reconnection fees. A customer was in arrears and had failed in the payment plan, but in working with the customer they learned that, it was not that the customer could not pay, they just could not follow the plan exactly. Hydro One recognized that they must be more flexible to meet customers' realities. Payment plans can be worked out to better suit customers. Also related to 'taking action', Mr. Pugliese asked participants to let Hydro One know what they wanted in terms of training programs for communities. They are willing to go to communities to work on individual bills, explain the bills, and get clients on plans; however, these activities take many visits. Another option is training people within communities to host these meetings and provide this service within the community. These programs are just getting started, but Hydro One will continue to work with communities in this area.

Chief R. Donald Maracle: The Chief noted that some councils loan monies to community members for bills in arrears. He asked what Hydro One could do for communities in this situation. Some people have had to go to high interest rate companies to borrow, which is a hard cycle for people to get out of.

- Mr. Pugliese responded that people would generally have to rely on social service agencies and that Hydro One does not have a policy on this issue, but can potentially look into it. In addition, he noted that they spoke with the Premier on affordability funding. The current program qualifiers are stringent but perhaps Hydro One can use the surpluses in cases such as this.
- **Follow up from Chief Maracle:** The Chief notes that in smaller communities there are no service agencies and have to depend on the band council.
- Mr. Martinez, Hydro One, noted that when they come to the community in March they will bring the United Way with them. Community members can apply for relief from the United Way. He has done this with First Nations communities before.
- Mr. Pugliese noted that this issue has come up before and is something that they want to look at. They are looking to support an adjudication process in order to address it. This is a potential suggestion for action going forward.

Chief Elaine Johnston: Chief Johnston noted that a lot of her people are living in poverty, so a payment plan will not help them. They are having a hard time paying for food. There are other social service programs, but those have a limit.

- Mr. Pugliese commented that Hydro One cannot address poverty in a general sense. It is a very broad, complex social issue. However, Hydro One can focus on the bills as part of their own social responsibility. Also related to community social services, perhaps Hydro One can support those through Hydro One's community giving program.

Peter Archibald, Councillor: Regarding Hydro One coming into communities and turning off power, Councillor Archibald asked if it was possible to put a load limiter on these houses. He reiterated that when the power is turned off pipes freeze causing unnecessary renovations that cost even more money. He also expressed frustration that Hydro One staff go on reserve to shut people's power off and do not even stop at the band office first. If this does not change, Councillor Archibald suggested that Hydro One staff would no longer be welcome in his community. He reiterates that concerns must be addressed, especially the delivery charges. He shared his position that the delivery charge should be removed altogether.

* Mr. Pugliese responded that Hydro One supports Councillor Archibald's position on the delivery charge; however, it is not Hydro One that controls that. Regarding Hydro One staff entering the community, Hydro One has heard this concern previously and believes that their staff must respect the community protocols. They should first visit the band office. Finally, with respect to the disconnection and whether there could be load limiters, Mr. Pugliese noted that there are resources on this that Hydro One is willing to share through their outreach activities.

Chief Wayne Pamajewon: Chief Pamajewon brought back the conversation on the agreement from 1951, which was signed by four communities. He inquired about how much revenue was generated through that agreement over the years. He would like to see the historical numbers. He also suggested the conversation on submersible cables should move forward.

* Mr. Pugliese responded that he is sure there must be information on the revenues generated through those agreements. He noted that he and the Chief Legal Officer had been going through all of the agreements to identify what had gone wrong in the past and where there are fixable issues. Hydro One wants to re-evaluate all of those agreements and resolve outstand issues. Regarding submersibles, Mr. Pugliese noted that they are happy to sit and meet to have a discussion. In addition, the Chief Operations Officer would be presenting later and would be better suited for that discussion.

Chief William Diabo: Chief Diabo spoke about delivery costs. He shared that they have houses in his community that they rent. They turn the breakers off in the summer and yet they still receive bills with an astronomically high delivery charge. He is seeking an explanation for that. In addition, he asked for more details about the First Nations rate and the consultation with First Nations on that issue.

* Mr. Pugliese noted that consultation has not started for Hydro One on that issue. Regarding the First Nations rate, that was a consultation conducted by the OEB last year.
* **Response from Chief Diabo:** The Chief noted that his community was not consulted and added that the Chiefs of Ontario does not consult for his community; rather, they only advocate for his community.
* Mr. Pugliese noted that Hydro One can provide more information on that consultation initiated by the OEB and on the request for a First Nations rate.

WELCOME REMARKS FROM THE PRESIDENT

Mr. Mayo Schmidt, President and CEO, Hydro One

Mr. Schmidt provided a warm welcome to the Grand Chiefs and Chiefs. He recognized that the participants were looking for action and outcomes. He noted that the Hydro One team was learning more about the issues that are facing First Nations. Many of the issues identified the previous day were brought up again at this session. Hydro One is going through a period of transition. As part of the transition, the company has taken a renewed focused on customer service. He assured participants that their voices are being heard, not just by the leadership team in attendance, but also the entire Board of Directors. Hydro One, being a publicly listed company, opens up an opportunity to advocate on behalf of customers, whereas before Hydro One just took instructions from the province. The leadership team has come to understand how painful the delivery charge is for First Nations and they are speaking with the province to try to address that. Hydro One serves 88 different First Nation communities, which represent a great deal of diversity. He noted the need to account for constitutionally protected rights and unique cultural connection to the land.

Mr. Schmidt shared that Hydro One met with the majority of the First Nations communities that they serve, which included over 200 community visits. He noted that they are looking to expand community visits and welcomed the participants to let Hydro One know if they were interested in a community visit. He appreciated the goals and aspirations, as well as the needs of First Nations rights-holders and landowners, in terms of business development and community relationships.

The rising cost of power is a serious concern and Hydro One would like to see lower rates. He assured the room that Hydro One staff were listening and taking notes which they will use to advocate First Nations concerns when meeting with the Premier and Minister of Energy, in making those points about affordability. Mr. Schmidt noted that Hydro One has information about how the rate increases occurred and plans for how they can be addressed. They will use this information to try and influence better outcomes for customers. Hydro One met with the OEB on the First Nations rate and supported reducing the delivery charge for First Nation communities. They also met with the Premier. Mr. Schmidt shared his optimism in seeing a policy change in the near future.

Regarding high bills and high arrears Mr. Schmidt noted that they are expanding the delivery of a new service model in First Nations communities. The new model centres on sitting down with customers face-to-face to review accounts and provide assistance where possible. To date, they have met with over 600 customers and are seeking to expand. Mr.. Schmidt stated that if this is of interest to participants, to let Hydro One staff know. He noted that in the coming months they will be developing new programs for sustainable relationships. He views this as not only good business but also the right thing to do.

Mr. Schmidt concluded by thanking attendees for participating, as well as thanking the Minister of Energy and Regional Chief Day for working together towards building a strong and sustainable relationship.

Chief Dean Sayers: The Chief began by thanking Mr. Schmidt for attending the meeting. He explained that Indigenous people in Ontario pay the most taxes of anyone. There was an agreement to share the economy with settlers based on the understanding that First Nations people do not have to pay taxes. In Ontario, this is largely unrecognized. Chief Sayers asked if Hydro One would be willing to honour the point of sales tax exemption for all Indigenous people in Ontario no matter where they live. This was his formal request. The Chief's second point is on working for mutual benefit; he wondered how working together would look, and what would be the benefits, in general.

- Mr. Schmidt asked his staff member, Ms. Lee Anne Cameron [First Nations and Metis Relations], to make a note on the issue of taxes. He stated that given the complexity of the tax system there would have to do some analysis on that. He committed to going back to Chief Sayers on that topic.
- Ms. Cameron sought to clarify Chief Sayers' statement; that the tax can be removed for customers on reserve once Hydro One receives a status number, but she believes what Chief Sayers is referring to is eliminating the taxes even for those First Nations who are not living on reserve.

- **Chief Sayers:** The Chief clarified that at the time the agreement was made, there was no differentiation between on-reserve or off-reserve.
- Ms. Cameron said that Hydro One would go back to their tax group to discuss as well as talk to the province. She noted that they had been audited several times by the Canadian Revenue Agency related to tax collection. She also noted that, on a personal level, she agreed with Chief Sayers.

Mr. Schmidt described recent conversations with the province where they sought to provide solutions to the challenge of high delivery charges. The Province is currently looking at those issues. Hydro One is seeking to make progress on the big issues, and is trying to get away from disconnecting customers; rather, they are seeking to turn the power back on and work with customers one-on-one to try and solve the challenges.

Chief Scott McLeod: Chief McLeod shared that his band council had to issue 220 cheques to Elders to assist them in paying their hydro bills. That is $88,000 in one month. He notes that it is not just the financial burden; they view it as insulting and immoral. The Chief shared that there are two major lines running through his First Nation, and yet leadership has to explain why citizens who are struggling are getting delivery charges. He noted that his community members are outraged, particularly because Hydro One does not pay anything to the community for the lines running through their territory and then Hydro One turns around and charges outrageous rates. They view this as money that is owed to them, and they need a conversation about that.

- Mr. Schmidt noted that Hydro One staff needed to meet with Chief McLeod on this issue and wondered if the contract lapsed or was ever renewed? He committed to reviewing these agreements.
- Ms. Cameron suggested that Mr. Gary Schneider, Hydro One, can talk with the Chief on this issue.
- **Chief McLeod:** The Chief explained that the issue cannot be resolved because the land is the First Nations' land, it was unsold and un-surrendered. It took 50 years to get the land back from the federal government. In the meantime, the delivery charges keep rising.
- Mr. Schmidt commented that Hydro One could work with the First Nations as a partner in approaching the federal government when these things are taking so long to resolve.

Peter Archibald, Councillor: Councillor Archibald noted that when it comes to projects in their area, the First Nations should be contacted for employment. He noted the case of Otter Rapids specifically. They had sent permits for the band council to review, and when the band signed off, the contractor said "oh sorry, no jobs." Councillor Archibald's second point is related to disconnections. He does not believe that Hydro One staff are aware of the new policies around working with people one-on-one to avoid disconnections because in his community they just cut people off. He noted that he sent a letter to Mr. Schmidt's office and received no response.

- Mr. Schmidt assured Councillor Archibald that he responds to every note that comes into his office. He asked that he resend a copy and he will respond. In terms of employment, Mr. Schmidt stated that he could not agree more and wants First Nations employees to participate in projects. He committed to putting people in touch with Ms. Judy McKellar, Executive Vice President, Chief Human Resources Officer. In regards to disconnection, Mr. Schmidt asked participants to let Hydro One know of anyone living without power. Hydro One wants to get them connected. If any community has people headed in that direction, Mr. Schmidt asked them to let Hydro One know and they will try and find a way

to manage. In addition, if your community would like Hydro One to make a community visit, just ask.
- **Councillor Archibald:** He commented that Hydro One comes to the community and does not want to hire his people.
- Mr. Schmidt noted that this might have something to do with Ontario labour law, and they will look into it.
- Mr. Martinez, Hydro One, announced that they would pass around a note and for participants to identify any preferred dates for community visits.

Chief Edward Wawia: The Chief shared that he did not get anything out of the presentations today. He felt that he needed to return to his community with answers for the Elders and young people about why their bills are so high. Based on this meeting he noted that nothing will be done about the high bills except another group of people will come to the community to show them how to manage their bills. That is degrading for his community members. The solution on offer is just extending their payments for a longer period of time. The Chief noted that what is actually required is getting serious about profit sharing so First Nations can deal with the huge bills.
- Mr. Schmidt clarified that Hydro One is in the transmission and distribution business, and it is the regulators who set the prices. Hydro One is indeed advocating getting better rates, but they cannot control the rates themselves. However, Hydro One can control certain things and make some changes such as infrastructure repairs and such. Hydro One can also provide assistance before a disconnection. He again encouraged people to approach Hydro One to see what they can do on that end. He reiterated that Hydro One is just one part of a much larger system. He also reiterated that the organization is undergoing a culture shift and asked that they be given a chance.

Steven Nootchtai, Councillor: Councillor Nootchtai began by thanking the organizers of the event. He noted that many of the concerns raised were also concerns for his community. Councillor Nootchtai provided a recommendation: that Hydro One uses their influence with their suppliers, because he views externalized costs as a Treaty issue. Hydro One has much more power than First Nations to influence change.
- Mr. Schmidt was in agreement with the speaker. He noted that Hydro One went from a Crown corporation to a commercial operation and in doing so has a greater influence on their suppliers. In addition, they are asking the province to make adjustments where necessary. He noted that, as a company, Hydro One has to get costs down as well. They are doing more work with less people and are reinvesting the savings back into stabilizing the system.

Chief R. Donald Maracle: Chief Maracle reminded the room that land was never surrendered to the Crown, yet the Crown gave letters of patent to others for some of his reserve land. Some members of his community live on that land part time. He wondered if their bills could be tax exempt, as their rights are being infringed on.
- Mr. Schmidt offered to talk to legal counsel on the issue and help investigate the situation. He noted that, if necessary, Hydro One could advocate the community's position with the provincial and federal governments as well.
- Mike Penstone, Vice President of Planning, Hydro One suggested that what the Chief was describing was a federal jurisdictional issue. The land was not surrendered. Secondly, the status of First Nations as it relates to tax is also a federal issue that would have to be determined by the Canadian Revenue Agency.

- **Chief Maracle**: The Chief restated that the land was not surrendered.
- Mr. Penstone responded that he understands the Chief's argument, but it is an argument that needs to be made to the federal government.
- **Chief Maracle**: Chief Maracle asked why Hydro One does not just try it and see what the Canada Revenue Agency says.
- Mr. Penstone responded that this might be an option for the Chief.

Chief Wayne Pamajewon: The Chief began by describing an issue his community had related to a road. The province was involved, and the First Nations took them to task on that. Cottagers were pushing the province to build a road west of his community. The community knew that those lands were still theirs. All the blasting required to build that road affected the aquifer and wells dried up. The community had to fight INAC on that issue. His community drilled the well and successfully negotiated with the Ministry of Transportation. Now the community has a water station, which requires power to operate. The Chief noted that there are many power outages and as a result, the community had to purchase generators for the well and the facility. There are a number of outstanding expenses related to power failures.

- Mr. Schmidt commented that Hydro One formed a group specifically to deal with water station outages. On occasion they have supplied the province with generators and fuel in the past. Mr. Schmidt suggested that perhaps Hydro One could support First Nations in this way, with the support of the province and the OEB.
- **Chief Pamajewon:** The Chief responded that his community had already expended that money
- **Lee Anne:** Ms. Cameron suggested that they would ask Mr. Penstone to speak to this point in the next presentation.

SYSTEM INVESTMENTS

Mr. Mike Penstone, Vice-President, Planning, Hydro One

Mr. Penstone explained the power system within the PowerPoint presentation. He explained that the transmission system map shows the system that takes the power from the generation to "load centres" through high-voltage transmission lines. The Hydro One distribution system (map) does not support the entire province. It mostly supports the rural part of Ontario. So, for example, Toronto uses Toronto Hydro for a distribution system rather than Hydro One. Most First Nations are in rural areas and are served by the Hydro One distribution system. The number of assets within the transmission and distribution systems is enormous and Hydro One are one of the larger transmitters in North America.

Question from Chief Elaine Johnston: The Chief asked how Hydro One does not service Toronto and if there is some type of agreement.

- Mr. Penstone responded that within their transmission network, Hydro One brings power to Toronto's boundaries and then Toronto uses its own distribution network to reach customers. There are operational agreements in place, as the operations and investment need to be coordinated.
- Mr. Penstone noted that the primary causes of interruption are equipment failure (49%) and weather (18%). Hydro One has to spend money to maintain or replace equipment. This costs roughly $1.4B annually. He added that a lot of the equipment is from the 1950s and 1960s and is reaching end of life. It will need to be replaced and Hydro One needs to ensure there is the money to do that.

Chief McLeod: The Chief asked if the rates covered the delivery and upgrades

- Mr. Penstone responded positively.
- **Chief McLeod:** Chief McLeod noted that he runs a business and when upgrades are required it comes out of his profit. He wondered why Hydro One did not operate that way.
- Mr. Penstone responded that Hydro One collects money to cover ongoing costs of operating the business and providing reliable service is their business and requires upgrades. He also noted that Hydro One does have a net income and Mr. Hubert, Hydro One, would be able to explain that more in the next presentation.

Steven Nootchtai, Councillor: Councillor Nootchtai questioned whether there were investments in innovation or research in order to replace the old equipment.

- Mr. Penstone responded that yes, Hydro One invests in finding better, less costly ways of delivering reliable service. One potential innovation is drones. Utility companies can use them, but there is a lot of resource and development work that goes into determining how they could be used. Specialized drones can be used to inspect the lines for example. . Also they are looking at technology that can identify failures in the system to address them quickly.
- Mr. Penstone noted that Hydro One is maintaining reliability in the transmission system by increasing capital investments (lines) and leveraging technology. He noted that disruptions to the distribution system are most often caused by trees (24%) and equipment failure (24%).
- Vegetation management is a sensitive issue for customers and landowners all across the province because it involves cutting down trees. Hydro One recognizes that it is controversial but the company's focus is on reliability. However, Hydro One workers should not be surprising homeowners with action taken on their trees. They are working to notify homeowners prior to cutting.
- Related to First Nations distribution connections, they are often long, heavily treed lines. There is an impact on reliability for those reasons.

Question from Ms. Amy Lickers: Ms. Lickers wondered if these distribution connections are less likely to get three phase power.

- Mr. Penstone responded that he is referring only to the performance of the wire. It is a separate issue related to the demands for electricity. Converting lines from single to three phases is because of high consumption.
- Related to maintaining reliability of the distribution system, Mr. Penstone is looking to reduce the number of outages per year through the renewal program, tree trimming and the smart grid and shortening the length of outages through improved outage response, monitoring and control.
- Mr. Penstone noted that Hydro One asked customers about their priorities and they responded that the priority should be minimizing costs and less of a priority on improving reliability. The survey included 300 customers in First Nations communities.
- In order to control costs Hydro One is pacing expenditures, undertaking vegetation management and moving to mobile technology. He noted that Hydro One spent $100 million this year on vegetation management.

Chief Paul Eshkakogan: The Chief noted that this morning a Hydro One representative said that they could not do anything about poverty in First Nations communities, yet the company spent $1.4 billion on equipment. He asked what percentage of that goes into First Nations communities in terms of contracts and employment. He suggested that there should be more effort in integrating First Nations communities and business and helping them get a piece of that $1.4 billion. When it comes to procurement, terms like "best efforts" are not effective. He referred to the use of "set asides" or sole source contracts. He also noted that training is an important component. Communities are getting better at drafting and negotiating Impact Benefit Agreements (IBAs) with industry. He did, however, observe that Ontario and its Crown corporations are lagging behind other sectors when it comes to meaningful and capacity building opportunities for First Nations. The Chief would like to see a table developed to move this work around contracts and employment/training forward. As an example of his frustration, the Chief noted that even on the issue of vegetation management, they could not get anyone on the project because of a union issue. He reiterated that they need jobs in his community to pay the bills. The Chief expressed a desire to come to an agreement to continue the dialogue related to unlocking job and contracting opportunities for First Nations.

- Mr. Penstone agreed with the Chief and noted that there have been instances where First Nations communities provided material and services for projects. Mr. Penstone directed the comment to his colleagues in procurement.
- A Hydro One representative agreed with the Chief and suggested that they do a workshop with the community and their businesses in order to participate in the Hydro One sourcing events. He also commented that he supported the idea of a table for dialogue and is considering what that would look like from a strategic perspective. He agreed that they needed to start those discussions.
- **Chief Eshkakogan:** The Chief noted that that was pretty weak language and something they are used to hearing. He noted that he does not believe any company is going to work with First Nations, despite their best efforts. Rather, what will work is when communities have something of value like contract work in their hands, businesses will come to them. Hydro One can choose the company that they want to work with and allow the community to build capacity through that relationship. There is a lot that can be learned from each other. His community established the Lake Huron Transmission Company and participated in a procurement process on the east/west line. It was ultimately not successful but it was a good learning process. Hydro One should be unbundling larger contracts to support First Nations, as they likely do not have enough capacity to do the full contracts. The Chief concludes that there are many things that can be done and companies that could partner with First Nations. In addition, he offered to make himself available to work on this issue with Hydro One.

Chief Patricia Big George: The Chief asked why Hydro One does not move forward on sole source processes for First Nations. Also, related to the work around vegetation control, the Chief asked where to find out more information.

- Mr. Penstone noted that a description of where they spend their money and how is included in all applications to the OEB. They are on the OEB website and they are also on the Hydro One website. The descriptions go into a great deal of detail. Hydro One staff would provide the links to those websites.

Chief Elaine Johnston: Chief Johnston expressed some concern about the survey, which determined that cost was more important than reliability. She noted that clearly they needed to deal with the high bills, but they also need reliable lines. Reliable lines are needed for economic development initiatives to work; it is how the community functions. She asked what plan was in place for those lines that are unreliable. She suggests perhaps a pilot project for other initiatives to deal with reliability.

- Mr. Penstone responded that the customer survey was only to determine customer priorities. Hydro One is not using the survey to justify ignoring the reliability aspects of the lines. He reassured the attendees that Hydro One continually monitors performance and where it is bad or degrading they will make investments. When lights go out in the community there are health and safety impacts. This is also part of determining where investments in reliability are made.

DISTRIBUTION RATE FILING (2018-2022)

Mr. Oded Hubert, Vice-President, Regulatory Affairs, Hydro One

Mr. Hubert described how Hydro One is going to the OEB with a distribution rate application that, if approved, would provide the necessary Revenue Requirement to operate the system for the next five years (2018-2022). This is the standard application that Hydro One has to complete (from now on, every five years). It is completely separate from the policy decision around a First Nations rate that the Minister will decide on.

To assist the OEB's work on a First Nations rate,

- Hydro One has given the OEB a significant amount of information to make their determination including the size of bills and the amount of the delivery charge compared to the commodity charge.

Also, the Premier asked Hydro One, among others, for advice on providing relief to rural customer, given that the delivery charge is often higher than the commodity charge.

Chief Elaine Johnston: wondered what was the difference between the All-Ontario rate and the First Nations rate.

- Mr. Hubert responded that the general distribution delivery rate is for all Hydro One customers. The Minister will decide the First Nations rate and then the Minister will tell the OEB what the First Nations rate will be. The general rates (other than the First Nations rate) are determined by the OEB, through Hydro One's application.
- Hydro One is filing this submission at the end of March and is looking for input before it is completed. Included in the submission will be results from the customer engagement surveys, and also the notes from this meeting. There are some First Nations that have actually represented themselves at the OEB, so there is a voice for First Nations at the hearings.

Chief R. Donald Maracle: thanked Hydro One for advocating for a reduction in the rates paid by First Nations. He asked if First Nations would benefit from the rural/remote reduction.

- Mr. Hubert responded that everyone within the R2 classification already receives a subsidy on their bills automatically.
- **Chief Maracle:** The Chief inquired as to the total profits for Hydro One last year.

Mr. Hubert responded that this figure is available online (Hydro One Limited's consolidated Net Income for 2016 was $721 M).

First Nations Representative [name unknown]: The participant wondered about the implications for members that do not live on reserve.

- Mr. Hubert noted that the Minister's letter which asked them to explore the idea of a First Nations rate specified on-reserve customers only.

- **First Nations Representative:** First Nations leadership has a responsibility for all of their members, no matter where they live.
- **Chief McLeod:** The Chief noted that it is a huge concern, if the rates for off-reserve First Nations go up; while on-reserve it goes down.

Chief R. Donald Maracle: Chief Maracle asked if hydro rates overall are going up 10% next year

- Mr. Hubert responded that not according to Hydro One's numbers. The PowerPoint presentation will explain further.
- Slide 6 showed the breakdown of electricity costs to customers. The diagram represents an average customer: 51% goes to electricity generation, 37% goes to Hydro One delivery charges, 5% is a sales tax, 3% is regulatory charges and line losses represent 4%.

Chief Elaine Johnston: Chief Johnston wondered why rates had increased so much.

- Mr. Hubert responded that the increase is due to a few factors: the increased cost of electricity, the move to eliminate coal, renewable energy and infrastructure costs.
- Slide 7 showed how distribution charges are spent by Hydro One: preventing outages (47%), upgrading the system (21%), customer service (12%), responding to power outages (10%), and information technology (7%) and, administration (3%).
- The next slide details how distribution rates are set by the OEB.
- Mr. Hubert explained that this year Hydro One could earn an allowed profit (Return on Equity) of about 8.78%.
- Slide 10 identifies the stages in developing and submitting an application to the OEB including preliminary matters (3-4 months), issues and discovery (2-3 months), hearing (3-4 weeks), and decision and approvals (2-4 months). In total, the process usually takes 8-12 months.
- Slide 11 shows that the Hydro One application must balance key considerations including customer needs and preferences, rate impact and asset needs.
- Related to customer needs and preferences, Hydro One called about 800 customers including 300 First Nations people. In general, First Nations had greater levels of dissatisfaction, more cost sensitivity and placed greater importance on keeping costs low. In general, the First Nations surveyed would accept a 1% bill increase if they saw some improvement in service. Many findings were similar with the non-First Nations respondents.
- Mr. Hubert's presentation also noted that shrinking consumption so the cost serving each consumer has to go up.

First Nations Representative [Name Not Heard]: The participant asked if the seasonal rate is more than the rural rate 2 (The R2 rate).

- Karen Taylor, Hydro One**,** explained that the charge is based on how much a customer consumes. She noted that the OEB is looking at moving those into fixed monthly charges and eliminating the variable component.
- Mr. Hubert noted that Hydro One is asking the OEB for rates for five years and will not be going back except for minor adjustments. However, over the five years, Hydro One can continue to search for productivity savings, innovations, and better technology and reduce costs. This could lead to more profit, but Hydro One has committed that if it were

more than a 1% increase above the allowed ROE, the additional profit would be shared 50/50 with customers.

Chief Patricia Big George: Chief Big George asked if this would affect the First Nations rate.

- Mr. Hubert responded that it would not change the First Nations rate and that they would all have to see how the First Nations rate unfolds.

Chief Elaine Johnston: Chief Johnston asked what is causing the decreasing consumption.

- Mr. Hubert responded that it was mostly due to conservation activities and economic conditions.
- Mr. Hubert concluded that the participants can send any additional questions via email.

WRAP UP

The Facilitator closed the meeting by mentioning that the PowerPoint presentations would be available. In addition, pictures of the artwork and copies of the notes will be distributed.

Summary points:

- Where they went from here will be determined by relationship building that will continue. There will be ongoing meetings set up including community meetings.
- Please judge Hydro One based on actions and results over the next five years.

The closing prayer was done by Elder Andrew Wesley.

Meeting Adjourned.

TAB 6

3.8. (5.4.5.2) ATTACHMENTS: MATERIAL INVESTMENTS

SA-01 Joint Use and Line Relocations Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	111.3
Primary Trigger:	Infrastructure Development Requirement		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One must meet contractual obligations to joint use partners as per existing Joint Use Agreements. In addition, a growing number of distributed generators have become third parties on poles owned by Hydro One, causing an increase in the number of upgrades required to Hydro One's distribution assets required by other parties.

Hydro One is also obligated to perform line relocation work at the request of Municipal and Provincial road authorities as per the requirements of the *Public Service Work on Highways Act* and associated Ministry of Transportation guidelines, as well as line relocation work requested by customers in accordance with Hydro One's Conditions of Service.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to perform the requested work would place Hydro One in violation of contractual obligations with the third party joint use partners; as well as could jeopardize Hydro One's occupation rights on the public road allowance.

Investment Description:

This investment addresses the externally driven requirements for joint use work and line relocations, as noted below. Due to the demand nature of this work, the total number of joint use and line relocation projects can vary year to year from 250 to 400 projects annually; with the cost of each project being less than $1 million.

<u>Joint Use</u>

Joint Use investments alter or upgrade Hydro One distribution line equipment in order to accommodate the use of this equipment by joint use partners. These partners may include telephone or cable companies (communication circuits), municipalities (street lighting), local distribution companies, or generators connected to the distribution system.

The type of upgrade or change required may involve increasing pole class to accommodate changes in pole loading, and/or increasing pole height to obtain appropriate ground clearances for public safety. These activities may also carry the cost associated with premature retirement of in-service assets.

Cost sharing provisions in joint use agreements allow Hydro One to recover costs resulting from requests to accommodate new attachments to its poles.

Line Relocations

Line relocation investments alter the location of Hydro One distribution line equipment in response to road modifications initiated by road authorities or in response to property development initiated by individual customer requests.

Hydro One occupies road allowances at no cost. However in return, Hydro One is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate specific road authority or property development requirements. Most commonly, this involves relocating lines to accommodate changes to roads, highways, and bridges.

The cost of the plant relocation is either fully or partially recoverable, depending on the specific circumstances of each project.

Risk Mitigation:

The risk to completion of this investment as planned is the fluctuation and volume of projects which must be completed on annual basis. This program, driven by third party requirements, can be subject to changing requests and additions. These risks are mitigated by maintaining open communication channels with the third party agencies – reviewing priorities and timelines for project completion.

Result:

The joint use and line relocation program will result in:

- Satisfying Hydro One's contractual and legal obligations with third party joint use partners, road authorities, and customers; and
- Maintaining property rights for distribution lines located on road allowances.

Outcome Summary:

Customer Focus	• Improve customer satisfaction with joint-use customers by providing joint use capabilities. • Deliver on customer requests in a timely manner.
Operational Effectiveness	• Realize reliability improvements, where possible, on upgrades or renewal of the distribution system in response to customer requests.
Public Policy Responsiveness	• Comply with contractual and legal obligations under the *Public Service Work on Highways Act* and Hydro One's Conditions of Service.
Financial Performance	• Realize cost savings by cost sharing, where possible, on upgrades or renewal of the distribution system in response to customer requests.

Costs:

The average gross investment cost for this program over the five year period is in line with the average historic gross spend over the last 5 years. The factors which affect the costs in this investment are the volume of requests and scope of such requests. The costs for the joint use and line relocation program are based on projections from joint use partners including new generator customers, road authorities and property development customer requests. Provincial government infrastructure initiatives can cause an increased in project volumes. Any significant changes to these projects would affect the overall investment cost.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacement and coordinating joint use and relocation projects with other sustainment programs where feasible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	45.5	46.0	46.6	47.2	47.8	233.1
Less Removals	5.1	5.2	5.3	5.3	5.4	26.3
Gross Investment Cost	**40.4**	**40.8**	**41.3**	**41.9**	**42.4**	**206.8**
Less Capital Contributions	18.7	18.9	19.1	19.3	19.5	95.5
Net Investment Cost	**21.7**	**22.0**	**22.2**	**22.6**	**22.8**	**111.3**

**Includes Overhead at current rates.*

SA-02 Metering Infrastructure Sustainment Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	75.9
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. With an asset base of this magnitude, it is reasonable to expect that there will be a number of meters and network devices that will fail to operate as intended and must be replaced in a timely fashion.

With the introduction of smart meters in 2006, customer meters have the capability to provide billing settlement data electronically. However, any disruptions in the electronic communication due to the failure of a meter or network device (i.e., collector or repeater), results in an estimated bill being generated to which customers have routinely indicated their displeasure.

Furthermore, replacement of failed components is critical to maintain a reliable meter infrastructure network and resultant source of billing settlement data to satisfy the OEB Distribution System Code Section 7.11 “Billing Accuracy” requirement to have 98% billing accuracy.

Alternatives:

This investment is non-discretionary. No alternatives were considered, since failure to perform the work to repair and/or replace the meters and associate network would be in violation of the OEB Distribution System Code Section 5.1 "Provision of Meters and Metering Services" and has the potential to negatively impact the reliable source of billing settlement data.

Investment Description:

This investment addresses the like for like replacement of failed metering devices and the maintenance of an adequate level of inventory of metering devices to ensure timely replacement.

The meter inventory consists of meters, repeaters, collectors and other electronic components used in the meter infrastructure network. The required inventory levels are determined based on the population size of particular meter or equipment model, and historical failure rates. The annual inventory purchases are dependent on which categories of equipment were deployed to replace failed equipment each year.

Based on recent operational experience, Hydro One estimates the approximate number of devices, consisting of meters and various network devices, that are required to be removed and replaced each year are as outlined below. The forecasted number of meter devices procured are lower than the number replaced since a portion of failed metering devices may be repairable.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Metering Devices Procured	27,000	25,000	25,000	25,000	27,000
Number of Metering Devices Replaced	29,880	27,000	27,000	27,000	29,000

Risk Mitigation:

The risk to completion of this investment as planned is the potential unavailability of resources in certain locations. This risk is mitigated by managing program resources and hiring temporary staff as required.

Result:

The meter infrastructure sustainment program will result in:

- Ensuring timely availability of meters and network devices;
- Complying with regulatory requirements; and
- Ensuring a reliable source of billing settlement data that increases customer confidence and satisfaction that bills are accurate.

Outcome Summary:

Customer Focus	• Reduce unwanted estimated customer bills. • Reduce customer interruption time by maintaining an adequate level of components to ensure timely replacement of failures.
Operational Effectiveness	• Increase efficiency by reducing number of manual reads. • Maintain meter network reliability to ensure a reliable source of billing settlement data.
Public Policy Responsiveness	• Comply with OEB Distribution System Code requirements to provide accurate and timely billing. • Comply with the *Electricity and Gas Inspection Act* to ensure meter accuracy.
Financial Performance	

Costs:

The costs for this program are projected based on these historic labour costs, material unit costs, and future anticipated needs. The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts;
- The volume and types of meters and network devices requiring replacement; and
- The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.

Controllable costs have been optimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	14.9	15.4	15.7	16.3	16.7	79.0
Less Removals	0.6	0.6	0.6	0.6	0.6	3.1
Gross Investment Cost	**14.3**	**14.8**	**15.1**	**15.6**	**16.1**	**75.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**14.3**	**14.8**	**15.1**	**15.6**	**16.1**	**75.9**

**Includes Overhead at current rates.*

SA-03 Meter Infrastructure Expansion Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	14.3
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	System Efficiency		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. With the introduction of smart meters in 2006, customer meters have the capability to provide billing settlement data electronically. Hydro One uses a metering infrastructure network to communicate with these smart meters; which has been constructed to take advantage of Canada and Rogers Communications ("the Carriers") cellular networks. However some of these meters cannot communicate reliably with Hydro One's meter infrastructure network, resulting in manually reading of these meters at specific intervals and estimated billing for the customer.

The OEB's Distribution System Code requires 98% billing accuracy, thereby limiting the use of estimated billing for customers. In the fall of 2015, Hydro One received an exemption from this OEB requirement to allow the use of estimated billing for approximately 170,000 customers with poorly communicating smart meters. This exemption was granted to the end of 2019.

Since that time, Hydro One has been working to establish reliable communication with these customers where economically viable in order to comply with the OEB direction for Hydro One to transition to time of use pricing. This improvement in communication levels is largely due to the success of the Carriers widening the capability of the cellular network. Another factoring contributing to the success was Hydro One's implementation of a flexible bill window, allowing billing data to be based on a meter read within a certain time frame rather than necessarily at a particular moment in time thereby creating a broader time window within which it can obtain a successful read.

Nonetheless, there remains approximately 123,000 meters that the meter infrastructure network still cannot communicate reliably with. By continuing to leveraging onging Carrier upgrades, there exists opportunties to allow more customers to communicate reliably.

Alternative 1: Maintain existing meter infrastructure network

Continue to operate the existing meter infrastructure network as is, and not leverage ongoing Carrier upgrades. This alternative is rejected as it will not improve the communication reliably nor does it align with OEB direction to move customers to time of use pricing and achieve 98% billing accuracy.

Alternative 2: Expand the meter infrastructure network *(Recommended)*

Expand the meter infrastructure network by leveraging the Carriers upgrades by installing collectors, repeaters and executing configuration changes to improve communicate reliably with meters. This alternative is recommended as it will reduce the resource requirements of manual meter reads and improve Hydro One's billing accuracy by reducing the number of meters with unreliable communication to 96,564 from 123,000 by the end of the five year period.

Investment Description:

This investment addresses the expansion of Hydro One's meter infrastructure network by leveraging the Carriers upgrades where economically viable. As the Carriers expand their network, Hydro One will expand their network by executing configuration changes and installing repeaters and/or collectors to enable reliable, remote, meter reading. This will result in a reduction of manual meter reading and the transfer of customers from two-tier billing to time-of-use rate schedules consistent with OEB direction for Hydro One to transition meters to time of use.

Hydro One has estimated that the proposed level of investment in the expansion of the communication network will result in approximately 26,436 customers transitioning from two-tier pricing to time of use over the five year period as outlined in the table below. In addition to meeting OEB guidelines, this will reduce the number of meters requiring manual meter reads.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Customers Transitioned to Time of Use	5,843	5,551	5,273	5,010	4,759

At the end of this period, approximately 96,564 meters (representing 78% of the existing 123,000 meters with unreliable communication) will still not have reliable communication and will remain on two-tier pricing, requiring exemption from the OEB requirement.

Risk Mitigation:

The risks to completion of this investment as planned are that the Carriers may not expand their networks at the forecasted rate or that their network expansion does not match the geographic areas where Hydro One is experiencing unreliable communication. These risks are considered low as there is a very competitive market demand for cellular service availability and performance that continues to drive the Carriers to expand their network.

Result:

The meter infrastructure network expansion program will result in:

- Providing reliable communication for remote reading of an additional 26, 436 meters; and
- Enabling the transition of 26,436 customers from two-tier to time of use pricing in accordance with OEB guidelines to do so where economically viable.

Outcome Summary:

Customer Focus	• Provide reliable remote meter reading enabling time of use pricing in order for customers to manage their electricity usage to reduce costs. • Increase customer confidence and satisfaction by providing a reliable communication network and reducing the number of bills issued on estimated data.
Operational Effectiveness	• Reduce resource requirements of manual meter reads.
Public Policy Responsiveness	• Comply with OEB direction to transition customers to time of use pricing, where economically viable. • Comply with OEB Distribution System Code Section 7.11 “Billing Accuracy” requirements to provide accurate and timely billing.

Financial Performance	• Avoid the cost of manual meter reading by reducing the number of meters with unreliable communication.

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The number of meters that can communicate reliably with a newly installed collector or repeater.

Controllable costs have been minimized through issuance of vendor contract to secure unit pricing for procurement of materials and the establishment of a standard on the minimum number of meters required to communicate reliably to justify installing a network device such as a repeater or collector.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.0	3.0	3.0	2.8	2.8	14.6
Less Removals	0.1	0.1	0.1	0.1	0.1	0.3
Gross Investment Cost	**3.0**	**2.9**	**2.9**	**2.7**	**2.8**	**14.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.0**	**2.9**	**2.9**	**2.7**	**2.8**	**14.3**

**Includes Overhead at current rates.*

SA-04 New Load Connections, Upgrades, Cancellations and Metering

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	581.6
Primary Trigger:	Customer Service Requests		
Secondary Trigger:	Mandated Service Obligations		

Investment Need:

Hydro One is obligated to connect new customers to the distribution network, upgrade services for existing customers, and install meters for new services under Hydro One's Distribution License. These system investments include the following activities:

New Connections**:** As part of its obligations under Hydro One's electricity distribution license and the distributor's responsibilities in the Distribution System Code ("DSC"), Hydro One is required to make an offer to connect all distribution customers on a non-discriminatory basis, upon written request for connection.

Service Upgrades: A service upgrade occurs when a customer requires a larger service entrance. A service upgrade normally requires the preparation of a service layout and replacement of secondary service lines. Transformers may also have to be upgraded, meters replaced and possibly additional transformation installed.

Metering: Installations may be required for new connections and service upgrades. Revenue meters, are funded under this program for new connections and service upgrades.

Cancellations: For cancellations of existing service, Hydro One is required to remove idle assets (such as transformers, poles, wires and meters) for safety and security reasons.

Alternatives:

Not proceeding with these investments would result in non-compliance with Distribution license requirements and with obligations under the DSC. This work is a regulatory requirement.

Investment Description:

Individual investments within these programs are managed on a project basis. Projects include design (service layouts), labour, material and other costs associated with actual physical connection or removal.

<u>New Connections:</u>

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to provide a connection service to new industrial, commercial, residential, and seasonal customers when requested. The division of costs between Hydro One and the customer is determined based on the company's connection policies, which are in accordance with the DSC requirements. A basic connection consisting of a service layout, overhead transformation, 30 metres of overhead conductor, and standard retail metering is provided free of charge to new customers that lie along the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cash flow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and network expansion. Customer contributions for system expansions and other recoverable costs beyond the basic connection are forecasted to be between $32.9 million and $36.7 million between 2018 and 2022. Projected costs for these programs are primarily based on historic demand and forecast load growth.

<u>Service Upgrades:</u>

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One is required to respond to existing customers who require a larger service to accommodate additional load and/or modify their electrical service entrance. These costs are classified as upgrade costs. A service upgrade normally requires the replacement of secondary service wires and the preparation of a service design. Also, it may be necessary to upgrade transformer(s), replace meters or install additional transformers. For standard service upgrades, Hydro One will provide a service layout, pole-mounted transformer, and the meter installation, if required. Costs for service modifications that exceed the cost of a standard installation would be recovered from the customer on a user-pay basis. Hydro One's customer capital contribution policies adhere to DSC requirements.

<u>Service Cancellations:</u>

Service cancellations are included in this program's "Removals" costs in the cost table in this document. These involve customers who request disconnection from the distribution system. Hydro One removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. As this work involves the removal of Hydro One owned equipment, these costs are accounted for under depreciation and are not capitalized.

The currently projected volume (number of units) of new connections, service upgrades and service cancellations from 2018 to 2022 is summarized in the table below.

Description	2018	2019	2020	2021	2022
New Connections	14,724	14,862	15,005	15,148	15,291
Service Upgrades	4,473	4,515	4,558	4,601	4,645
Service Cancellations	5,562	5,614	5,668	5,722	5,776

Risk Mitigation:

Hydro One connects several thousand customers to its distribution system every year. The main risk to this program is volume and timing of the customer requests. Every effort is made to prioritize these projects in order to meet the required service obligations. This prioritization and timing is completed at a service centre level through scheduling of work. Communication is maintained with the customer to ensure expectations are being met.

Result:

- Connect new customers and satisfy the requirements of the DSC and Hydro One's distribution license;
- Upgrade the services of existing customers;
- Remove assets when services are cancelled and mitigate safety risks; and
- Satisfy the requirements of the DSC and Hydro One's distribution license.

Outcome Summary:

Customer Focus	• Fulfill customer requests for connections and upgrades within established time frames to improve customer satisfaction.
Operational Effectiveness	• Ensure all new connections or upgrades meet latest standards. • Remove assets when services are cancelled to mitigate safety risks.
Public Policy Responsiveness	• Comply with requirements in the DSC and distribution licence to provide new connections or service upgrades when requested by customers.
Financial Performance	• Leverage financial benefits on company-wide productivity initiatives.

Costs:

Planned costs for the program are based on historic actual costs and a forecast of future load growth, factoring in future savings initiatives. The actual program costs will be comprised of the individual projects (connections, upgrades, cancellations) completed on an annual basis. Controllable costs are minimized by ensuring that all projects are completed using standard processes and within standard unit costs. Any unforeseen issues at a work location, outside the established unit cost, will result in increased costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	153.3	157.5	161.6	167.5	172.1	812.0
Less Removals	10.5	10.8	11.2	11.6	11.9	56.0
Gross Investment Cost	**142.8**	**146.7**	**150.5**	**155.9**	**160.2**	**756.0**
Less Capital Contributions	32.9	33.8	34.7	35.9	37.0	174.3
Net Investment Cost	**109.9**	**112.9**	**115.7**	**120.0**	**123.2**	**581.6**

**Includes Overhead at current rates*.

Witness: Lyla Garzouzi

SA-05 Distributed Generation Connections

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	16.6
Primary Trigger:	Customer Service Requests		
Secondary Trigger:	Mandated Service Obligation		

Investment Need:

The Distribution System Code ("DSC") and Hydro One's distribution license obligate it to connect generation facilities that meet the requirements of the DSC. Hydro One's generation connection investments fund additions and modifications required to connect generating facilities to the distribution system. Generators make capital contributions to this work in accordance with Hydro One's connection policy and the DSC. Similar to load customers, Hydro One gives credit to the customer based on the forecasted load for station services of the distributed generator.

Alternatives:

This is a demand-based program for connecting new distributed generation. There are no viable alternatives as not proceeding with these investments would result in non-compliance with the requirements of Hydro One's distribution license and the DSC. This work meets a regulatory requirement.

Investment Description:

Individual investments within these programs are managed on a project basis. Projects involve estimating, design, labour, material and costs associated with actual physical connection of new generators.

Hydro One's investment plans are based on Ministry of Energy ("MOE") directives on distributed generation facilities and the IESO's Feed-in Tariff ("FIT") programs for distributed generators of different sizes, as well as other procurement initiatives from the IESO. The cost allocation requirements are as set out in the DSC. These determine the investments that are presented in this section.

The DSC divides DGs into five size categories: micro, capacity allocation exempt small, small, mid-sized and large. In Section 1.2 – Definitions, each of the five size categories is defined:

- Micro-embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 kW or less;
- Capacity allocation exempt small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line;
- Small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1 MW or less in the case of a facility connected to a 15 kV or greater line;
- Mid-sized embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 MW or less and a) more than 500 kW in the case of a facility connected to a less than 15 kV line; and b) more than 1 MW in the case of a facility connected to a 15 kV or greater line; and
- Large embedded generation facility – an embedded generation facility with a name-plate rated capacity of more than 10 MW.

Based on the definitions in the DSC, Hydro One places DGs into four categories for planning purposes:

1. Capacity Allocation Required (“CAR”) DGs which includes large DGs, mid-size DGs and small embedded DGs that are not capacity allocation exempt;
2. Capacity Allocation Exempt (“CAE”) DGs;
3. Capacity Allocation Exempt generators that are Net-Metered (“CAE-NM”); and
4. Micro-embedded DGs (including MicroFIT and Micro-embedded Net-Metered).

Hydro One makes lines and stations equipment upgrades to mitigate the above factors. The numbers of estimated projects are summarized below:

DG Category	Forecasted				
	2018	2019	2020	2021	2022
CAR	6	5	5	5	5
CAE	200	170	160	110	110
CAE -NM	295	280	305	335	370
Micro Embedded	200	200	200	200	200

At the time of writing, the identified material projects for 2018 are set out below.

Project	Name Plate Capacity (kW)	DG Category	Target In-Service
Kirkland Lake TS – DX Feeders	3,000	CAR – FIT project*	2018
Wendover HVDS – DX Feeders	12,000	CAR – Large renewable procurement project*	2018
Muskoka TS – DX Feeders	11,760	CAR – Large renewable procurement project*	2018

**Descriptions of FIT and large renewable procurement projects are provided in Section 3.5 of the Distribution System Plan.*

The connection requirements for each project vary depending on its size. For the CAR and CAE projects, the investments are broken down into three components: (1) Renewable Enabling Improvements ("REI") which are upgrades to existing lines; (2) "Expansions" which are actual line extensions; and (3) Connection Assets. The cost allocation for each component is based on Hydro One's connection policy and is in accordance with the DSC. All project connection costs are recoverable from the customer if the source of energy is non-renewable. If the source of energy is renewable, then a portion of the expansion cost (up to $90,000/MW) and 100% costs under REI is funded by Hydro One pursuant to the DSC. Costs of Expansions exceeding $90,000 per MW and the cost for any upstream station upgrades, if required, are recoverable in full from the customer.

Hydro One's distribution system is radial in design, with limited transfer capability to supply customers. The system was designed to move power from the transmission system downstream towards customers. As a result, the amount of generation capacity connected to Hydro One's distribution system is generally constrained by a variety of engineering factors, including but not limited to:

- equipment ratings;
- reverse power flow constraints;
- supply feeder current ratings;
- power quality; and
- remaining short circuit capacity at transmission stations.

These constraints are addressed on a project-by-project basis with engineering involvement when required. This may entail new line expansions, protection system upgrades, control system upgrades, new voltage regulators, voltage regulator control upgrades, line and station recloser upgrades. Associated costs include procurement, engineering, and project management costs associated with each project. Costs have been minimized through standardized design and procurement processes.

Consistent with the requirements of O. Regulation 330/09 under the *Ontario Energy Board Act, 1998*, a portion of the costs associated with the connection of renewable generators is allocated to Hydro One ratepayers and a portion of the costs are allocated to all provincial ratepayers. The allocation of costs is explained in Exhibit G1. The allocation of costs to Hydro One ratepayers and provincial ratepayers is different for Expansion assets and for REI assets. Connection assets are paid for by the generator customer.

Risk Mitigation:

Hydro One connects many DGs to its distribution system every year on demand. The main risk to this planned execution of this program is volume and timing of the customer requests.

DG projects are prioritized in order to meet the required service obligations. This prioritization and timing is completed through scheduling of work. Hydro One maintains communications with the customer to ensure that all requirements are met so the parties can complete their connection by the agreed upon in-service date.

Result:

- Connect new generators and satisfy the customers' timelines;
- Upgraded distribution lines as required; and
- Compliance with the requirements of the DSC and Hydro One's distribution license.

Outcome Summary:

Customer Focus	• Improved customer satisfaction by connecting new generators within contractually established time frames.
Operational Effectiveness	• Ensure all upgrades reflect latest standards and future load and generator forecasts.
Public Policy Responsiveness	• Compliance with requirements in the DSC and Hydro One's distribution licence to connect qualifying generators.
Financial Performance	• Lower engineering costs using standardized design and work practices.

Costs:

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	16.1	14.6	14.4	13.4	13.7	72.3
Operations, Maintenance & Administration and Removals	-	-	-	-	-	-
Gross Investment Cost	**16.1**	**14.6**	**14.4**	**13.4**	**13.7**	**72.3**
Less Capital Contributions	12.0	11.2	11.1	10.5	10.7	55.7
Net Investment Cost	**4.1**	**3.4**	**3.3**	**2.9**	**3.0**	**16.6**

**Includes Overhead at current rates.*

SR-01 Distribution Stations Demand Capital Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	12.3
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Safety		

Investment Need:

Service interruptions or unplanned system deficiencies associated with various distribution station assets occur and require an immediate response by Hydro One personnel. Asset failure or extreme weather may result in service interruptions that require restoration of power to maintain reliability. Over the past five years, there has been an average of 59 interruptions per year related to station equipment.

Hydro One also performs station inspections; rural stations every six months and urban stations monthly. These regular inspections may also identify damaged or failed distribution station assets that pose a safety hazard or customers may report power quality issues. Hydro One is obligated to replace these assets in accordance with good utility practice and the requirements of the Distribution System Code.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to quickly respond to service interruptions or other situations where assets have failed would violate the Distribution System Code and result in unacceptable reliability and safety risks.

Investment Description:

This investment addresses the replacement of failing or failed distribution station equipment in a timely manner in order to maintain distribution system reliability, safety, and/or power quality in situations where the assets cannot be repaired, and replacement is the only viable option in compliance with the Distribution System Code. Stations are key critical assets in that a large number of customers are impacted by station related failures. Examples of the most common work that is undertaken under this distribution station demand program include:

- Replacement of power transformers that have failed or are failing, must be replaced immediately to maintain the integrity of the system, also transformers that generate customer complaints with noise levels that exceed the guidelines must be replaced to comply with the requirements set out by the MOECC;
- Replacement of assets that have become significantly overloaded due to unexpected customer loading variations;
- Replacement of failed reclosers, or reclosers whose fault interruption levels have become exceeded or are close to being exceeded; and
- Replacement of failed or failing insulators, switches or poles within the station.

These failures are difficult to predict, but must be addressed quickly because they generally result in customer interruptions or present significant safety risks. Planned expenditures in this investment are projected based on historical trends and adjusted to reflect recent experiences.

Risk Mitigation:

The work in this investment is unplanned in nature. However, there are risks to executing such unplanned work including the availability of the mobile unit substations ("MUSs") and engineering resources. These risks are mitigated by ensuring that there is always at least one MUS available for emergent work in each voltage/capacity category and by having a process to enable reprioritization of engineering resources to support the immediate and emergent work as required.

Result:

From this investment, customers will benefit from sustained reliability resulting from the replacement of failed, failing and overloaded station equipment in a timely manner. The replacement of failing and overloaded station equipment before the failures occur results in fewer customer interruptions. The replacement of failing equipment also mitigates safety issues.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by minimizing the customer interruption duration by carrying out unplanned outages in a timely manner.
Operational Effectiveness	• Maintain distribution system reliability, safety, and/or power quality. Reduce safety risks associated with failed equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	

Costs:

The costs for this demand program are projected based on these historic costs and future anticipated needs. The average investment cost for this program over the five year period is in line with the average five year historic spending. The factors which affect the costs in this investment are the following:

- The scope of the replacement required to address the failure;
- The type and number of failed assets requiring replacement (i.e. transformers, switches, reclosers, etc.); and
- The ratings of the equipment requiring replacement.

Controllable costs have been minimized through the standardization of station designs and equipment ratings, establishment of unit price contracts with vendors, and maintaining a spare inventory for replacement of failed equipment to minimize outage time.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.5	2.5	2.6	2.8	2.9	13.2
Less Removals	0.2	0.2	0.2	0.2	0.2	0.9
Gross Investment Cost	**2.3**	**2.3**	**2.4**	**2.6**	**2.7**	**12.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.3**	**2.3**	**2.4**	**2.6**	**2.7**	**12.3**

**Includes Overhead at current rates.*

SR-02 Mobile Unit Substation Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	26.9
Primary Trigger:	Failure Risk		
Secondary Trigger:	Operational Functionality		

Investment Need:

Hydro One owns, maintains and operates a fleet of 30 mobile unit substations ("MUS") located across Ontario to support Hydro One's distribution stations that are designed primarily with only one transformer and with very little transfer capability. These MUS's perform an integral role in the operation of Hydro One's distribution system and are utilized for the following purposes:

- To offload distribution stations during maintenance and capital activities;
- For emergency power restoration in the event of a transformer or other distribution station component failure; and
- For load relief for distribution stations.

The management of Hydro One's MUS fleet is required to ensure that an adequate, safe and reliable fleet is available to satisfy these outage requirements noted above. The MUS fleet must adhere to the requirements of the Highway Traffic Act. Under the Highway Traffic Act, each MUS must receive an annual vehicle safety and structural inspection from an approved facility to certify that they meet minimum safety requirements. If an MUS does not pass the annual inspection, it cannot be transported. As a result, it is imperative that high risk MUS trailers are addressed to ensure usability.

As documented in DSP Exhibit 2.3, thirteen of the MUS fleet is in the high risk category resulting from deteriorated trailers, transformers, and other components in failing condition. The prolonged use of high risk MUS's could increase risk to Hydro One employees and the general public. There is also a need for higher MVA capacity MUS's to support heavier loaded stations, and MUS's with under load tap-changers to provide for voltage regulation.

There continues to be strain placed on the MUS fleet resulting from Hydro One's proposed work programs to address ageing infrastructure on the distribution system. Each year, approximately 30% of planned station work is deferred due to an insufficient number of available MUSs. In 2016, there were 121 scheduled MUS deployments to stations to support planned maintenance and capital work. Of the 121 scheduled outages, 31 were cancelled due to MUS unavailability. To ensure there is an adequate number and type of MUSs to accomplish all planned and unplanned station work and to minimize customer outages, additions to the MUS fleet are required. An inadequate MUS fleet has an adverse impact on emergency failure response that would jeopardize customer reliability and would negatively impact the ability of Hydro One to proceed with maintenance and capital work programs.

Alternative 1: Reactive Component Replacements

Wait for MUS transformer and trailer components that are at high risk to fail, and replace the failed MUS transformers and trailer components on a reactive basis. This alternative is rejected for several reasons. When MUS components such as MUS transformers or trailer components fail, the MUSs are unavailable until the failed components are replaced. The lack of availability of appropriate level of MUS fleet would have a negative impact on customer service, emergency power restoration and system reliability. Furthermore, the lead time to replace a failed major MUS component such as the transformer or trailer is expected to be 1.5 years; which would limit the capability of the MUS fleet to support emergency power restoration and/or capital and maintenance activities.

Alternative 2: Planned Component Replacements

Replace individual major MUS assets identified as high risk on a component basis. While this alternative is viable where only one of the major components is at high risk; it is not ideal when multiple MUS assets (i.e., trailers and transformers) are at high risk and in need of replacement. This alternative is rejected as the assessment of the MUS fleet, as documented in DSP Exhibit 2.3, has identified multiple assets in deteriorated condition. The replacement of MUS components on an individual basis will also not allow for higher MVA MUS transformers with voltage regulation capability to be installed on existing MUS trailers due to space and weight limitations. Furthermore, this alternative also does not address the shortfall in the MUS fleet.

Alternative 3: Planned Full MUS Replacements

Replace six MUS's at end-of-life. This alternative addresses the condition of the existing fleet by replacing half of the MUS's identified as high risk, with the remaining seven high risk MUSs to be replaced beyond the planning period. However, like Alternatives 1 and 2, this alternative does not address the shortfall in the MUS fleet. This alternative is rejected as the existing MUS fleet level is insufficient to address demands of the proposed work program and address emergency power restoration.

Alternative 4: Planned Full MUS Replacements and Fleet Expansion *(Recommended)*

Replace six MUS's at end-of-life to address the condition of the existing fleet identified as high risk, and expand the fleet with the procurement of three additional MUS's to address the shortfall in the MUS fleet. This alternative is recommended as it attempts to address the immediate needs identified for the MUS fleet to ensure system reliability is maintained and begins to alleviate backlog by making strategic expansion to the fleet.

Investment Description:

This investment addresses the replacement of MUSs that are at end-of-life, and addresses a shortfall in MUSs required to support the distribution system and proposed work programs.

The MUS fleet identified for replacement is based on MUS trailers and transformers in high risk, and are prioritized based on their level of risk and number of years beyond their expected service life. As outlined in DSP Exhibit 2.3, twelve of the MUS transformer condition assessments fall into the high risk category, while nine of the MUS trailers are in high risk. Also some of the MUS transformers have limited capacity or lack voltage regulation capability, which limits the utilization of the MUS. The appropriate level of MUS fleet is determined based on having MUSs which can be deployed to stations to support failures and restore customers within eight to twelve hours, and to have sufficient MUSs to allow for the completion of planned and unplanned capital and maintenance work.

Based on this assessment, six MUSs are planned for replacement and three new MUSs will be procured to expand the fleet over the five year period as outlined in the table below.

	2018	2019	2020	2021	2022
Number of MUS Replaced	2	1	2	1	0
Number of MUS Procured	0	0	0	1	2
Total	2	1	2	2	2

The MUSs will be replaced with units that have higher MVA capacity and will include voltage regulation. The new MUSs will also be equipped with electronic reclosers capable of remote operation and interruption of higher fault conditions. The specification for the replacements is as follows:

- Four MUS's with capacity of 10MVA, and voltage rating of 44kV – 12.5/8.32kV;
- One MUS with capacity of 7.5MVA, and voltage rating of 27.6kV – 8.32kV; and
- One MUS with capacity of 15MVA, and voltage rating of 115kV–27.6/25/12.5/8.32kV.

Of the three planned MUS purchases, two will be 10 MVA capacity with voltage rating of 44kV – 12.5/8.32kV, and one will be 7.5 MVA capacity with voltage rating of 27.6 kV – 8.32kV.

Risk Mitigation:

The risks to completion of this investment as planned are the time required to execute the procurement process, and the availability of vendor to manufacture and deliver the MUSs. Depending on when in the year the manufacturer receives the request for procurement, they may be fully booked and not able to immediately accommodate the request. These risks are mitigated by early evaluation of vendors, and by providing MUS procurement forecasts to vendors in advance to ensure that they will be able to accommodate the requests and issuance of the purchase orders in a timely matter.

Result:

The mobile unit substation program will result in:

- Ensuring a safe and reliable MUS fleet to respond to station failures in a timely manner;
- Obtaining an adequate MUS fleet to support failures with emergency power restoration and offload distribution stations to execute the proposed work program without unacceptable outage impacts to customers; and
- Maintaining the condition of the MUS fleet to mitigate risks to Hydro One staff and the general public.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by ensuring an adequate level of MUSs to provide emergency power restoration to failure events.
Operational Effectiveness	• Maintain the reliability of the distribution system by obtaining an adequate level of MUSs to carry the distribution station load while performing capital and maintenance work to mitigate power disruption to customers.
Public Policy Responsiveness	• Comply with Ministry of Transportation licensing requirements by ensuring the units are roadworthy and electrically functional.
Financial Performance	• Utilization of MUSs provides a cost effective alternative to constructing redundant transformation at distribution stations across the province.

Costs:

The factors which can affect the unit price of each MUS include the following:

- The specification of the MUS requirement replacement (i.e. MVA capacity of the transformer, Primary voltage(s), Secondary voltage(s), etc); and
- The cost of material and term of procurement contracts.

Controllable costs have been minimized through standardization of the MUS purchasing specifications with standardized MVA capacity for given voltage levels (i.e. 10 MVA for the 44 kV – 12.5/8.32 kV MUS's, and 7.5 MVA for the 27.6 kV – 8.32 kV MUS's). A general outline agreement with vendors for MUS unit prices will be established to further control costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.5	5.7	5.8	5.9	6.0	26.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**3.5**	**5.7**	**5.8**	**5.9**	**6.0**	**26.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.5**	**5.7**	**5.8**	**5.9**	**6.0**	**26.9**

**Includes Overhead at current rates.*

SR-03 Station Spare Transformer Purchases Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	18.6
Primary Trigger:	Failure		
Secondary Trigger:	Reliability		

Investment Need:

Transformers comprise the single largest component of Hydro One's distribution station asset base. Hydro One owns, maintains and operates 1,222 distribution station transformers. As outlined in DSP Exhibit 2.3, 23% of the distribution station transformer condition assessments fall into the high risk category.

Hydro One's distribution stations are designed primarily with only one transformer without on-site spare transformers that can be switched into service in the event of a failure, and typically have very little transfer capability based on the radial design of the distribution system. Each distribution station transformer supplies approximately 1,200 customers; hence a distribution station transformer failure is highly impactful to customers.

Over the past five years, there has been an average of nine spare transformer deployments per year to support failed transformers, as well as transformers on the verge of failure based on oil samples, demonstrating major oil leaks or violating noise guidelines set by the Ministry of Environment and Climate Change ("MOECC"). In these instances, when a station transformer fails, service is initially restored with the installation of a mobile unit substation ("MUS") until a spare transformer can be transported and installed at the station.

In order to ensure timely response in the event of a failure and maintain system reliability, a sufficient number of spare transformers are required as the lead time to procure transformers can range from 6 to 12 months. If the spare transformer inventory is not maintained, MUSs will be deployed to support failures for prolonged periods of time. Planned project and maintenance work would be deferred, resulting in an increase in failures.

Alternative 1: Reactive Procurement of Replacement Transformer

Deploy spare transformers currently in inventory to support failures, without replenishing the spare transformers which were deployed. Once all the existing spare transformers are depleted, Hydro One would no longer continue to maintain an inventory of spare transformers. Rather, transformer replacements would only be procured after the failure event has occurred. This alternative is rejected as the current fleet of MUSs cannot support this level of utilization. MUSs would be required to remain in service for extended periods of time until a replacement transformer could be purchased (typically 6 to 12 months). This would minimize the MUS's availability to support the proposed maintenance and capital work program, and provide emergency power restoration for other system failures which may occur, resulting in a negative impact on system reliability. Deferral of planned capital and maintenance work will result in an increase in failures. Once the failures exceed the number of available MUSs, system reliability will decrease and customers will be without power for extended periods of time.

Alternative 2: Maintain Sufficient Stock of Spare Transformers *(Recommended)*

Continue to maintain a sufficient inventory of spare transformers to address transformer failures by replenishing the spare transformer inventory when spare transformers are deployed to support failures. This alternative is recommended as it addresses transformer failures in a timely manner; and minimizes the utilization of MUSs for extended periods of time, enabling MUS availability to support the proposed maintenance and capital work program and maintain system reliability.

Investment Description:

This investment addresses the procurement of spare transformers for distribution stations as needed to support the in-service population. These spare transformers are used as replacements for failed units, replacements for transformers with escalated internal heating which must be forced out-of-service, replacements for noisy transformers identified through customer complaints which violate MOECC guidelines, and replacement for transformers with a major unexpected defect identified during routine inspection (i.e. failed tap-changer or significant oil leaks) which are not economical to repair.

The optimal number of spares Hydro One maintains is based on a probabilistic risk analysis model of each transformer category. Transformers are categorized by MVA capacity, primary voltage, secondary voltage, step-down transformers versus voltage regulators, auto voltage regulation capability, 3-phase versus 1-phase and bushing style.

The model determines the optimum number of spares required for each group of transformers by taking into consideration several factors including demographics, failure rates, delivery lead time and repair/replacement time. As outlined in DSP Exhibit 2.3 the failure rate of station transformers is on average 11 transformers per year. To address the failures, there has been an average spare deployment of 9 units per year.

Based on a recent assessment of the spare transformer fleet, and in consideration of previous spare transformer deployments, the proposed level of transformer replacements under the station refurbishment investment, and the optimum level of transformer spares projection of 149 units by 2022, thus the expectation is that 27 spare transformers will be required to be procured over the five year period in order to support failing and failed units as outlined in the table below.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Transformers Procured	4	5	6	6	6
Expected Number of Spares Deployed	9	9	9	9	9
Transformers in Inventory	164	159	155	152	149

The transformers purchased under this investment will vary in size and type, dependent on the spare that is deployed to support a failure event, in order to replenish the spare inventory to support the sizes and types of the in-service transformer fleet. Careful consideration is given to the available number of spares in each group. These spare transformers will be purchased only for instances where spare transformers deployments result in the spare category being below the required stock level.

With an average of 9 spare deployments per year, overall, this investment level will reduce the spare transformer inventory over the planning period from 164 spares to 149 spares, however, system reliability is expected to be maintained as long as planned replacements continue.

Risk Mitigation:

The risk to completion of this investment as planned is the availability of transformer vendors to manufacture and deliver the spare transformers in a timely manner. Manufacturer lead times are typically 6 to 12 months; and depending on when in the year the manufacturer receives the request for procurement, they may be fully booked and not able to immediately accommodate the request. This risk is mitigated by providing transformer purchase forecasts to vendors in advance to ensure that they will be able to accommodate the requests, and issuance of the purchase orders in a timely matter.

Result:

The station spare transformer program will result in:

- Sustaining reliability of the distribution system by replacing failed and failing transformers with new units from the spare inventory in a timely manner; and
- Reducing the number of customer interruptions by replacing transformers identified on the verge of failing.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by replacing failed or failing transformers in a timely manner to maintain system reliability.
Operational Effectiveness	• Maintain safe and reliability operation of the distribution system by maintaining an adequate level of spares. • Minimize the utilization of MUSs for extended periods of time to support failures; thereby ensuring the MUS availability to support maintenance and capital work program.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	• Realize cost savings through planned replacements of transformers identified as failing prior to failure as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the following:

- The actual number of transformer failures and demand transformer replacements which occur in year that require spare deployment; and
- The type of transformer requiring spare deployment, as the costs of the spare transformers can vary based on transformer specifications such as: voltage, capacity and tap-changer requirements.

Controllable costs have been minimized through standardization of transformer purchasing specifications with standardized MVA capacities for given voltage levels, and development of unit pricing with the transformer vendor.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.6	3.4	4.1	4.2	4.3	18.6
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**2.6**	**3.4**	**4.1**	**4.2**	**4.3**	**18.6**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.6**	**3.4**	**4.1**	**4.2**	**4.3**	**18.6**

**Includes Overhead at current rates.*

SR-04 Distribution Station Planned Component Replacement Program

Start Date:	Q1 2018	Priority:	Medium
In-Service Date:	Program	Plan Period Cost ($M):	11.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One owns, operates, and maintains 1,005 distribution stations across the province. As outlined in DSP Section 2.3, Hydro One performs inspections and preventative maintenance to assess the condition of the assets (i.e., switches, insulators, support structures, station service, fences and grounding) at distribution stations. These assessments identify a number of distribution station components that are in deteriorated condition, as outlined in DSP Section 2.2. Other influencing factors that affect the operation of the distribution station include components that have safety issues, substandard design or manufacturer defects (i.e., certain models of switches which are prone to failure due to seized bearings, seizing load interrupters and failure of porcelain insulators). The management of these components is required to mitigate these safety and environmental risks and maintain the reliability of the distribution system.

Alternative 1: Reactive Replacements

Wait for distribution station components to fail while in service and replace them on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Reactive management of the distribution station components will lead to increased failures resulting in increased safety risks given the emergency nature of the work and degraded reliability for Hydro One's customers.

Alternative 2: Planned Component Replacements (*Recommended*)

Planned replacement of distribution station components identified in deteriorated condition or that have deficiencies, safety issues, substandard design, manufacturer defects. This alternative is recommended as it maintains the safe and reliable operation of the distribution stations.

Investment Description:

This program addresses the individual replacement of distribution station components. The components are identified annually for replacement based on the condition of the asset. These replacements are coordinated with maintenance activities, where possible, to minimize the number of outages. Replacements under this program include but are not limited to the following:

<u>Switches</u>

Switches that are prone to failure due to seized bearings, load interrupters, and/or damaged porcelain insulators require replacement to ensure the reliability and operability of the system.

<u>Structures</u>

Mobile unit substation poles and “dead-end” poles identified in deteriorated condition require replacement to maintain the reliability of the system.

<u>Station Service</u>

Batteries and chargers identified in deteriorated condition require replacement to ensure the operation of protection and control devices, breakers, and circuit switchers in the event of a loss of station service power supply. These devices support reliability and protect other assets on the system.

<u>Fences and Grounding</u>

Station fences identified in deteriorated condition or of substandard height as well as damaged or stolen grounding components require replacement to maintain public safety and security.

The proposed plan is to replace an average of 35 distribution station components annually over the five year period, as noted in the table below. The capital investment for each component replacement is below $1 million. This is expected to maintain the overall condition of the station assets.

Component	**2018**	**2019**	**2020**	**2021**	**2022**
Switches	10	10	11	14	15
Structures	15	15	16	21	22
Other	5	5	5	6	5
Total Component Replacements	**30**	**30**	**32**	**41**	**42**

These planned component replacements are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in ISD SR-06.

Risk Mitigation:

The risks to completion of this investment as planned are outage scheduling and mobile unit substation availability. These risks are mitigated by identifying and planning the work in advance and in a timely manner to ensure that work can be coordinated with existing maintenance work.

Result:

The distribution station component replacements program will result in:

- Mitigating the risk of safety concerns with failed or defective assets;
- Maintaining the reliability of the distribution system; and
- Mitigating the risk of lengthy equipment outages from component failures that affect customers.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by minimizing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by reducing asset failure incidents.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a station inspection.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the number and the type of assets identified for replacement during the routine station inspections and preventative maintenance.

Controllable costs have been minimized by coordinating replacements with regular maintenance schedule, where possible. In situations where a station refurbishment is planned in the near-term, component replacement is bundled with the refurbishment to reduce costs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.1	2.1	2.2	2.7	2.8	11.8
Less Removals	0.1	0.1	0.2	0.2	0.2	0.8
Gross Investment Cost	**1.9**	**2.0**	**2.0**	**2.5**	**2.6**	**11.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.9**	**2.0**	**2.0**	**2.5**	**2.6**	**11.0**

**Includes Overhead at current rates.*

SR-05 Distribution Station Feeder Protection Upgrade

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	12.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Grid Modernization		

Investment Need:

Hydro One's distribution system has about 2,438 non-sub transmission primary feeders. The majority of these feeders (93%) are protected by various types of station reclosers, while the remaining 7% are protected by circuit breakers and station fuses with no reclose capability.

The 7% of distribution feeders that are protected by circuit breakers and fuses with no reclose capabilities have reduced reliability performance for customers. In the event that a fuse experiences a momentary fault resulting in a disconnection, the feeder would be subject to a sustained outage until it is manually re-energized. This situation is avoided when the feeder protection is upgraded to utilize a recloser (with reclose capability) to protect the distribution feeder.

There is also a subset of reclosers that have become technically obsolete and are no longer supported by the manufacturer. Not only are there no spare parts available should repairs be required, but these reclosers are also more prone to failure. Feeders with obsolete recloser types are only 2% of all feeders, however they account for 5% of all defects identified in 2016.

Furthermore, there are concerns that some of the existing reclosers have reached 95% to 100% of the reclosers' ratings and are approaching a point that the reclosers will no longer have sufficient short circuit and/or interrupt capability to meet the distribution station short circuit levels. Short circuit levels at these stations have increased due to several factors, such as: system reconfiguration, addition of generation on feeders, and/or installation of higher rated station transformers. These reclosers need to be replaced prior to short circuit levels reaching beyond 100% of the recloser's rating.

Alternative 1: Reactive Replacements

Wait for the feeder protection to fail while in service and replace them on a reactive basis. This alternative is rejected for several reasons. Reactive management of the feeder protections will lead to increased unplanned outages due to failures of the reclosers and fuses at unexpected times. This may result in safety risks, reduced feeder protection and reduced reliability for Hydro One's customers. Also the existing feeder protection fleet would require a large stock of spares to be maintained as there are various types and voltage levels of reclosers and fuses on the distribution system. In circumstances, where the existing reclosers are obsolete, modification of the existing structure and station design may be required to install a new recloser design which can take up to 12 months.

Alternative 2: Planned Replacements *(Recommended)*

Proactively install new electronic vacuum type reclosers with communication capability, where the existing protective device has become insufficient and at risk of failure due to condition, short circuit capability, or the lack of reclosing capability. This alternative is recommended as it upgrades the feeder protection before a failure occurs and improves reliability on feeders that are being upgraded from fuse protection to recloser protection due to the reclose capability of a recloser. Also the new electronic controlled vacuum type reclosers have a higher operation limit before maintenance is required compared to the traditional oil filled hydraulic type reclosers, and are also equipped with communication capability for remote controllability.

Investment Description:

This investment addresses concerns with the existing feeder protection through the installation of new vacuum type reclosers with electronic control and communication capability.

These new reclosers are designed for up to 10,000 reclose operations with minimal maintenance. This will reduce the maintenance required compared to oil filled hydraulic type reclosers which are only designed with a threshold of 58 to 272 reclose operations before a maintenance cycle is required. These new electronic reclosers also contain multiple protection settings that can be changed without the need for intrusive upgrades to the recloser, making them more flexible and adaptable to system changes than fuses and hydraulic reclosers. Furthermore, these new reclosers also provide remote control and monitoring capability features to allow automation of the distribution system. This capability modernizes the distribution system, which allows for monitoring and remote control of the recloser. This added benefit can reduce the restoration time when an outage occurs.

Feeder protections are identified and prioritized for replacement based on risk assessment of distribution feeders, in consideration of the following:

- Feeders where station short circuit current level and/or fault current is approaching short circuit rating/interrupt rating of the existing feeder protection;
- Feeders currently protected by fuses that provide reduced reliability to customers as this type of feeder protection has no reclose capability; and
- Feeders where the existing feeder protection is technically obsolete and/or historically prone to failure.

Each feeder protection upgrade will vary in scope and duration depending on the type of existing feeder protection and the design of the station. The forecast of the number of feeder protection requiring replacement annually over the five year period is provided in the table below. The capital investment of each feeder protection replacement is below $1 million.

	2018	2019	2020	2021	2022
Number of Replacements	13	13	13	12	12

By the end of 2022, approximately 8% of all distribution feeders would have been upgraded to new electronically controlled vacuum type recloser with remote communication capability. These planned feeder protection upgrades are limited to cases where no other assets at the station require replacement. If other assets at the station have deteriorated and require replacement, then the work is bundled into an integrated Station Refurbishment project as outlined in ISD SR-06.

Risk Mitigation:

The risk to completion of this investment as planned is the time required to execute an upgrade if the distribution station has a substandard design or insufficient clearances, to ensure the newly installed recloser meets current standards. This risk is being mitigated by identifying requirements early in the engineering phase such that proper resources can be allocated to complete the feeder protection upgrade.

Result:

The feeder protection upgrade investment will result in:

- Modernizing the distribution system with feeder reclosers that have a higher operation limit and can be monitored and controlled remotely;
- Improving safety to those stations where fault current levels are on the rise, with the installation of new electronic vacuum type recloser that have a higher interrupt capability and rated for higher fault current levels; and
- Improving customer experience by reducing number and duration of potential sustained customer interruptions.

Outcome Summary:

Customer Focus	• Reduce the number of potential sustained interruptions to customers by adding reclose capability.
Operational Effectiveness	• Improve operational efficiency by adding monitoring and remote controllability to feeder protection. • Address rising station short circuit levels by increasing interrupt capability of the feeder protection.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Enable the potential for more renewable generation to be connected by increasing short circuit rating of the feeder protection.
Financial Performance	

Costs:

The factors that impact the cost of a feeder protection upgrade include the station design and the existing type of feeder protection that is being upgraded. These factors determine the complexity of the installation and the amount of alteration required for each station to install new reclosers.

Controllable costs have been minimized through the procurement of new reclosers that have a higher operation limit before maintenance is required when compared to the traditional oil filled hydraulic type reclosers and allow for monitoring and remote control capability that have the added benefit of reducing the restoration time when an outage occurs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.4	2.5	2.5	2.6	2.7	12.7
Less Removals	0.1	0.1	0.1	0.1	0.1	0.6
Gross Investment Cost	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**	**12.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**2.3**	**2.3**	**2.4**	**2.5**	**2.5**	**12.1**

**Includes Overhead at current rates.*

SR-06 Distribution Station Refurbishment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	148.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Capacity Upgrade		

Investment Need:

Hydro One owns, maintains, and operates 1,005 distribution stations in Ontario. Each distribution station serves an average of 1,200 customers. A vast majority of these stations are a single transformer design with limited transfer capability.

In the event of a failure of the transformer, the supply to the transformer, or the bus work at a distribution station; all customers supplied by that distribution station would experience an interruption of service until power restoration was achieved through either a repair of failed equipment or connection of a mobile unit substation ("MUS"). These power restoration efforts can take 12 to 24 hours depending on the severity of the failure and location of the station. Over the last five years there has been an average of five transformer failures per year which caused interruption of service.

As outlined in DSP Exhibit 2.3, the main power equipment at these distribution stations are transformers and 23% of these transformers are classified as high risk based on condition assessment. There are also concerns with the condition of some of the structural components of distribution stations, including rotting high and low voltage wood structures, failing tube and clamp structures, fence and grounding systems.

Some other factors contributing to the need for the refurbishment of a distribution station are: loading requirements, lack of MUS facilities, obsolete equipment, environmental spill risk mitigation, and safety issues or a combination of all of these factors. Details relating to these factors can be found in DSP Exhibit 2.3.

Alternative 1: Reactive Component Replacements

Wait for distribution station equipment to fail and replace the failed components on a reactive basis. This alternative is rejected for several reasons. Reactive management of stations would lead to degraded reliability for Hydro One's customers as a result of station failure increases and the duration of outages being longer in length (12 to 24 hours). The reactive replacements would be limited to only addressing the failed component and would not address other components in deteriorated condition that are also at risk of failure. The volume of failures would increase and the MUS and spare transformer fleet would need to be expanded in order to address the additional failures in a timely manner to maintain the customer reliability. Where a station requires additional capacity, the increase in capacity cannot be addressed with a reactive component replacements strategy.

Alternative 2: Planned Component Replacements

Replace individual components identified in high risk condition on a planned component basis. This alternative is viable where only one component at a distribution station is in deteriorated condition (as documented in Investment Summary Document SR-04). Planned replacements have the advantage of avoiding customer outages by arranging for an alternative supply (MUS or load transfer) unlike reactive replacements. However, this alternative is not ideal when multiple components are in deteriorated condition, as individual replacements work is not integrated resulting in increased costs due to multiple mobilizations to replace the different assets.

Alternative 3: Planned Station Refurbishments *(Recommended)*

Refurbish entire stations that have multiple assets in high risk condition, before failures occur. This alternative is recommended as it addresses the needs identified at the distribution station to maintain reliability for Hydro One's customers supplied from that station in the most cost effective manner, consistent with the findings of the customer engagement process. Furthermore for distribution stations in high risk condition where a capacity upgrade is required, station refurbishment is the only feasible alternative as an increase in capacity requires several components of the station need to be replaced or modified (i.e. larger transformer, additional reclosers, increase structure size and station footprint, change conductor and cable size).

Investment Description:

This investment addresses the refurbishment of distribution stations to address station equipment in high risk condition where the likelihood of a failure is high. The level of investment has been determined based on this assessment of condition and in consideration of: customer preferences, safety concerns, compliance requirements, and the benchmarking recommendation to incorporate test result data into the condition assessment.

The proposed plan is to refurbish an average of 15 distribution stations per year over the 5 year period, as noted in the table below. This is expected to maintain the current level of transformers in poor condition at 23% (even though the overall age of the fleet will increase) with the goal of maintaining the current level of station reliability in line with customers' preference to balance reliability and rate impacts.

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2018	Blenheim DS	1	27.6	8.32	3.6	5
	Duff DS	1	27.6	8.32	5	7.5
	Gorrie DS	1	44	8.32	5	7.5
	Haliburton DS	1	44	12.5	6	7.5
	Joyceville DS	1	44	12.5	6	7.5
	Meaford Vincent DS	1	44	4.16	5	5
	Sowerby DS	1	115	27.6	2.2	7.5
	Wainfleet DS	1	27.6	8.32	3	7.5
2019	Birch Island DS	1	44	12.5	6	6
	Brigden DS	1	27.6	8.32	3.6	5
	Chatham Raleigh DS	1	27.6	8.32	3.6	7.5
	Dack DS	1	44	12.5	3	5
	Grand Valley DS #2	1	44	12.5	3	7.5
	Hawley DS	1	44	8.32	4	7.5
	Ostrander DS	1	27.6	8.32	5	7.5
	Owen Sound DS #2	1	44	8.32	2	5
	Shedden DS	1	27.6	8.32	3.6	5
	Stratford DS	1	27.6	8.32	3	5
	Stratford East Hope DS	1	27.6	8.32	3	5
	Troy DS	1	27.6	8.32	5	5
	Ufford DS	1	44	12.5	3	5
	Waupoos DS	1	44	8.32	5	7.5
	Whitedog DS	1	13.8	12.5	2	5

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2020	Aspdin DS	1	44	12.5	6	7.5
	Carleton Place Edmund DS	1	44	4.16	5	5
	Cobalt DS	1	44	12.5	3	5
	Colpoys Bay DS	1	44	12.5	6	7.5
	Island Grove DS	1	44	8.32	5	5
	Kenora DS	1	115	12.5	3.6	5
	Millington DS	1	44	8.32	5	5
	Oil Springs DS	1	27.6	8.32	4.7	5
	Nottawaga DS	1	44	8.32	5	5
	Reid Corners DS	1	44	8.32	3	5
	Tara DS #2	1	44	8.32	3	5
	Washago DS	1	44	8.32	5	5
	Williamstown RS	1	44	44	25	25
	Woodland Beach DS	1	44	8.32	5	5
	Wroxeter DS	1	44	8.32	3	5
2021	Aberdeen DS	1	44	8.32	5	5
	Bothwell Corners DS	1	44	8.32	5	5
	Cedar Mills DS	2	44	27.6	20	20
	Constance DS	2	115	27.6	30	30
	Crown Hill DS	1	44	8.32	5	5
	Dwight DS	1	44	12.5	6	7.5
	Emsdale DS	1	44	12.5	6	7.5
	Elmvale DS	1	44	8.32	3	5
	Emo DS	1	44	12.5	3	5
	Ferndale DS	1	44	12.5	6	7.5
	Harriston DS #2	1	44	8.32	5	5
	Keswick DS	1	44	8.32	10	10
	Lake Vernon DS	1	44	12.5	6	5
	Milverton DS #2	1	44	8.32	5	5
	Oxmead DS	1	44	8.32	7.5	7.5
	Willow Beach DS	1	44	8.32	5	5
	Wolsey Lake DS	1	44	12.5	6	5

Year	Station Name	Number of Transformers	HV	LV	Existing Capacity (MVA)	New Capacity (MVA)
2022	Belleville DS #2	1	44	8.32	5	7.5
	Blackstock DS	1	44	8.32	5	5
	Brunelle DS	1	44	8.32	5	5
	Chemung DS	1	44	8.32	5	5
	Coboconk DS	1	44	12.5	10	7.5
	East Luther DS	1	44	12.5	6	5
	Horning Mills DS	1	44	8.32	5	5
	Listowel Davidson DS	1	44	4.16	5	5
	Madoc DS #2	1	44	12.5	6	5
	Pinestone DS	1	44	12.5	10	7.5
	Pleasant Point DS	1	44	12.5	6	5
	Precious Corners DS	1	44	8.32	5	5
	Rutherglen DS	1	44	12.5	2.3	5
	Schreiber Winnipeg DS	1	115	13.8	6	7.5
	Sherburne Andrew DS	1	44	4.16	5	5
	Tory Hill DS	1	44	12.5	6	5
	West Lorne DS	1	27.6	8.32	5	5
	Woodville DS	1	44	8.32	5	7.5

Each station refurbishment will vary in size and scope. The refurbishment will address: aged transformers and structures, defective equipment, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues. The stations will be refurbished to comply with present standards.

Risk Mitigation:

The risks that can impact the completion of a distribution station refurbishment project are: procurement of real estate to accommodate the station configuration, and environmental remediation of the site. These risks are mitigated by determining the requirements of the new station early in the project planning process and requesting a land survey and environmental site survey before detailed design work has started.

Result:

The station refurbishment program will result in:

- Ensuring sufficient capacity to meet customer loading requirements for the foreseeable future;
- Addressing assets in poor condition to reduce customer interruption time; and
- Resolving operational and safety issues and mitigating environmental spill risk where the risk exists.

Outcome Summary:

Customer Focus	• Reduce customer interruption time by minimizing the number of outages at distribution stations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution station by addressing degrading equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system.
Financial Performance	• Realize cost savings by addressing multiple degrading components within the station as part of the same project.

Costs:

The factors which affect the cost of this investment are the following:

- The station design and required station capacity;
- The level of environmental remediation required at the distribution stations; and
- The condition of the structure and level of refurbishment required.

Controllable costs have been optimized through consideration of the station load forecast to avoid additional investments due to overloading in the foreseeable future, and the use of a risk based approach when deciding the level of environmental remediation required.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	16.2	31.8	36.4	37.1	37.8	159.3
Less Removals	1.1	2.2	2.5	2.6	2.6	11.1
Gross Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**

**Includes Overhead at current rates.*

SR-07 Distribution Lines Trouble Call and Storm Damage Response Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	431.0
Primary Trigger:	Failure		
Secondary Trigger:	Safety		

Investment Need:

Service interruptions associated with distribution lines invariably occur that require immediate response by Hydro One personnel. Extreme weather or asset failures may result in a service interruption that requires restoration of power to customers. Regular patrols and inspections may also identify damaged or failed distribution line assets that pose a safety hazard or customers may report power quality issues. Hydro One personnel must be dispatched to assess and resolve any urgent deficiency in accordance with good utility practice and the requirements of the Distribution System Code.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to respond to service interruptions or other system deficiencies would violate the OEB Distribution System Code and result in unacceptable reliability for customers and safety risks.

Investment Description:

This investment encompasses the capital costs of asset replacements associated with responding to trouble calls, storm damage, power interruptions and other situations that pose reliability or safety risks and require immediate attention in compliance with the Distribution System Code.

The distribution lines trouble call and storm damage response program includes the following activities:

- Emergency pole and line equipment replacements,
- Emergency submarine and underground cable replacements,
- Storm damage response and resolving service interruptions caused by adverse weather conditions,

- Post trouble-call response and providing permanent solutions to any temporary repairs that were required during an emergency or a service interruption,
- Power quality response requiring modifications to the system to resolve unacceptable voltage or frequency levels, and
- Damage claims, including payment for third party damage that Hydro One cannot recover.

All other trouble call and storm damage response costs which cannot be capitalized are allocated to the OM&A work program as documented in Exhibit C, Tab 1, Schedule 2.

Risk Mitigation:

The work in this investment is unplanned in nature. However, there are risks to executing such unplanned work including the number of asset failures and storm events and the availability of qualified resources. This risk is mitigated by diverting qualified resources from other projects to complete restoration activities.

Result:

The distribution lines trouble call and storm damage response program will result in:

- Maintaining reliability of the distribution system by ensuring timely response to trouble calls, service interruptions, and power quality complaints,
- Mitigating safety risks of defective or failed assets, and
- Satisfying customer and regulatory requirements.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by minimizing the customer interruption duration by carrying out unplanned outages in a timely manner. • Mitigate customer complaints related to power quality and reduce public safety hazards.
Operational Effectiveness	• Maintain the safe and reliable operation of the distribution system.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	

Costs:

Planned expenditures for this demand program are projected based on historical costs, factoring in anticipated needs and inflation over the period. The factors which affect the costs in this investment are the following:

- The volume of the asset failures and storm events which occur on an annual basis.
- The scope of the work required to address asset failures and storm events.

Any significant changes to these would affect the costs.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacements.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	97.2	99.1	100.9	103.5	105.5	506.1
Less Removals	11.7	11.9	12.1	12.4	12.6	60.7
Gross Investment Cost	**85.5**	**87.2**	**88.8**	**91.1**	**92.8**	**445.4**
Less Capital Contributions	2.8	2.8	2.9	2.9	3.0	14.4
Net Investment Cost	**82.7**	**84.4**	**85.9**	**88.1**	**89.8**	**431.0**
Net Costs in System Renewal	75.6	77.1	78.5	80.5	82.0	393.5
Net Costs in System Service	7.1	7.3	7.4	7.7	7.8	37.4

**Includes Overhead at current rates.*

Note: *Costs for forestry and premium time incurred as part of storm damage restoration are captured as part of OM&A Trouble Calls.*

SR-08 Distribution Lines PCB Equipment Replacement Program

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	72.8
Primary Trigger:	Mandated Obligation		
Secondary Trigger:	Substandard Performance		

Investment Need:

Hydro One owns, operates, and maintains 450,000 pole top transformers, 54,000 pad mount/submersible transformers and 3,000 pole mounted capacitor units; all of which are oil filled equipment. Prior to year 1985, a chemical compound known as a polychlorinated biphenyl ("PCB") was widely deployed in dielectric and coolant fluids in the manufacturing of oil filled electrical apparatus. However, this manufacturing practice was discontinued in the late 1970's when it became evident that PCBs build up in the environment and exposure to high levels can cause harmful health effects. In 2008, Environment Canada enacted legislation mandating that all oil-filled equipment whose insulating oil contains greater than 50 ppm of PCBs be removed by December 31, 2025. Therefore Hydro One must remove all such oil-filled equipment. Hydro One's distribution assets which are oil-filled consist solely of pole top transformers, pad mount mount/submersible transformers and pole mounted capacitor unit.

Alternatives:

This investment is non-discretionary. No alternatives are considered, since failure to remove PCB contaminated distribution line equipment would place Hydro One in violation of Environment Canada regulations and result in increased public health and safety risks.

Investment Description:

This program addresses the removal and replacement of distribution line oil-filled equipment (i.e., pad mount transformers, pole top transformers and pole mounted capacitor banks) whose insulating oil contains PCB contamination levels are greater than 50 ppm. All of Hydro One's pad mount transformers have already been tested as part of the PCB inspection and testing program, and all units with greater than 50 ppm of PCBs have been replaced.

All of Hydro One's pole-top transformers manufactured prior to 1985 will require inspection and oil sampling testing. To date, approximately 10 to 15% of the transformers have be inspected and tested. Hydro One proposes to inspect and test the remaining transformers at a consistent rate over the period from 2018 to 2024.

From past experience with PCB testing, approximately 8% of these transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination. The replacement of the pole-top transformers is slated to lag the PCB inspection and testing program by one year, allowing time for the identification of contaminated transformers and optimization of a plan to replace the transformers that minimizes the impact to customers. Based on historic sampling results this would result in approximately 2,400 to 2,600 replacements per year to ensure that the program will be completed by the 2025 deadline set out by Environment Canada.

Capacitor units cannot be tested for PCBs without causing them significant damage. Therefore, all of Hydro One's capacitors manufactured before 1985, will require replacement. Hydro One proposes to replace the units at a consistent rate over the period from 2018 to 2024.

Risk Mitigation:

The risk to completion of this investment as planned is based on the uncertainty of the volume and exact location of the PCB contaminated equipment exceeding the allowable threshold of 50 ppm. This risk is mitigated by the establishment of an inspection and testing program to identify all oil filled equipment that must be replaced under legislative requirement and an associated process to replacement the identified contaminated equipment.

Result:

The distribution lines PCB equipment replacement program will result in:

- Mitigating health and safety risks associated with PCB contamination by removing the affected line equipment; and
- Ensuring compliance with environmental legislation.

Outcome Summary:

Customer Focus	• Mitigate potential health and safety hazards to customers and the public by removing the contaminated lines equipment.
Operational Effectiveness	• Realize improvement of distribution lines by replacing the old PCB contaminated equipment with new equipment.
Public Policy Responsiveness	• Comply with Environment Canada legislation to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.
Financial Performance	• Avoid non-compliance penalties arising from a failure to complete the mandated PCB elimination by 2025.

Costs:

The costs for this program are projected based on historic sampling results and future anticipated replacement needs which lag the PCB inspection and testing program by one year. The factors which affect the costs in this investment are any unforeseen issues at each work location, for example all new installations must meet Electrical Safety Authority requirements, so where a transformer is to be replaced, minimum pole height standards are mandated which could result in multiple pole and other equipment replacements.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement, and coordinating with other sustainment programs where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	13.3	13.6	13.8	21.2	21.6	83.5	113.0
Less Removals	1.7	1.7	1.8	2.7	2.8	10.7	14.4
Gross Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**11.6**	**11.8**	**12.1**	**18.5**	**18.9**	**72.9**	**98.6**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018 and forecasted costs beyond 2022.*

Witness: Lyla Garzouzi

SR-09 Pole Replacement Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	579.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	Safety		

Investment Need:

The structural integrity of a distribution line is largely dependent on the poles that support the line. Hydro One owns, maintains and operates approximately 1.6 million poles, of which 99% are wood poles.

The condition of wood poles deteriorates over time due to decay and rot, insect and rodent damage, mechanical impact, or other factors that reduce the structural integrity of the pole. Once a pole's condition has deteriorated to the point that it has a significant risk of failure under adverse weather condition, it is deemed to be at end-of-life. During storm conditions, poles that fail can sometimes trigger "cascading failures", which result in the failure of a larger number of distribution system assets.

As outlined in DSP Exhibit 2.3, there are currently approximately 67,000 poles in poor condition that are at high risk of failure. By the end of 2022, it is forecasted that an additional 77,000 poles will be added to this high risk category due to deteriorating condition.

In addition to concerns with condition, there are still a subset of 39,000 red pine poles that are demonstrating premature degradation, as documented in previous proceedings (EB-2013-0416, EB-2012-0136 and EB-2009-0096), that require replacement.

Furthermore, one of the finding of the benchmarking study discussed in DSP Section 1.6 found that Hydro One's poles replacement rate of approximately 10 700 pole per year over the past five years is slower than the comparison utilities. The study also found that the average pole on the Hydro One system is on average eight years older than the comparison utilities.

Alternative 1: Reactive Replacements

Wait for the poles that are at end of life to fail and replace the failed poles on a reactive basis. This alternative is rejected for several reasons. The cost of reactive replacements is more expensive as documented in DSP Exhibit 2.3. Reactive management of the poles will lead to increased failures resulting in a risk to public safety and degraded reliability for Hydro One's customers. Also the volume of poles requiring replacement will quickly increase to the point where the volume of trouble calls will become unmanageable.

Alternative 2: Planned Pole Replacements at Historic Rate

Planned replacement of end of life poles at the historic rate of replacement. This alternative is rejected as it would not address all of end of life poles within the five year period resulting in a backlog of poles which will lead to more frequent and/or longer duration outages for Hydro One customers.

Alternative 3: Planned Pole Replacement at an Increased Rate (Recommended)

Planned replacement of end of life poles at an increased rate (as noted in the following table) that balances asset needs, resource availability, and cost impact to customers. The number of poles at high risk of failure requiring replacement will be slightly reduced over the plan. This alternative is recommended as it will maintain reliability of the distribution system.

Investment Description:

This investment addresses the replacement of poles that are at end-of-life, and addresses the subset of red pine poles demonstrating premature degradation. Poles are inspected on a regular basis, and are identified and prioritized for replacement based on an asset risk assessment that considers factors such as: condition, performance, demographics and criticality.

Hydro One has been gradually ramping up the number of poles replaced each year to a sustainable level of replacement that balances the needs of the asset, resource availability, and the rate impact to customers.

Hydro One is sensitive to customer needs and will manage the population of poles in poor condition that are at high risk of failure over the five year plan so as to reduce cost impacts to customers. There are currently a large number of poles in poor condition that are at high risk of failure and it is forecasted that this number will be slightly reduced to 99,000 poles (including the red pine pole subset) over the plan. Poles are prioritized for replacement based on their impact on reliability and potential safety risks. The table below outlines the planned volume of poles to be replaced throughout the five year period.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Poles Replaced	9,600	14,300	16,000	16,123	16,128

Pole replacement costs and accomplishments are tracked and reported monthly. Depending on the types of poles requiring replacement (i.e. pole height, pole class, number of circuits, etc.) and the accessibility conditions of the area, the cost of replacement can vary. Where possible, the efficiency of this investment is maximized by bundling work and replacing poles in close proximity to each other. Larger line rebuilds are funded by the "Distribution Lines Sustainment Initiative" program as outlined in ISD SR-12.

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, the number of storms in recent years this has not been an issue.

Result:

The pole replacement program will result in:

- Reducing the risk of pole failure by replacing poles in poor condition;
- Reducing safety and reliability risks on the distribution system; and
- Ensuring compliance with Canadian Standards Association standards.

Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing wood poles prior to failure. • Focus on balancing the rate impact to customers while addressing the replacement need and risks associated with end of life poles.
Operational Effectiveness	• Maintain safe and reliability operation of the distribution system by proactively replacing end of life poles.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with Canadian Standards Association standard by replacing wood poles that have deteriorated to 60% of their design strength.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

Pole replacement costs and accomplishments are tracked and reported monthly. The factors which affect the costs in this investment are the following:

- The types of poles requiring replacement (i.e. pole height, pole class, number of circuits, etc.);
- The location accessibility conditions of the area in which the poles are being replaced. Accessing off road locations can be more costly due to the use of specialize equipment; and
- The cost of material and term of procurement contracts.

Controllable costs have been minimized through balancing the pole types and locations selected for pole replacements in a given year and by standardization the procurement of materials and procedures for equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	83.8	127.4	145.3	149.2	152.1	657.8
Less Removals	10.1	15.3	17.4	17.8	18.2	78.8
Gross Investment Cost	**73.8**	**112.1**	**127.9**	**131.3**	**133.9**	**579.0**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**73.8**	**112.1**	**127.9**	**131.3**	**133.9**	**579.0**

**Includes Overhead at current rates.*

SR-10 Distribution Lines Planned Component Replacement Program

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	35.3
Primary Trigger:	Failure Risk		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeders lines across the province. As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of line equipment (i.e. cross arms, nest platforms, overhead conductor, regulators, reclosers, sentinel lights, transformers, and switches) on those feeders. These condition assessments have identified a number of distribution line components that due to their condition, are near the end of their expected service life. Additionally, there are a number of components on the system that are substandard or that pose environmental risks. The management of these components is required to mitigate these safety and environmental risks and maintain reliability of the system.

Alternative 1: Reactive Replacements

Wait for the distribution line equipment to fail while in service and replace it on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Reactive management of distribution line equipment will lead to increased failures resulting in risks to employee and public safety and degraded reliability for Hydro One's customers.

Alternative 2: Planned Component Replacements (*Recommended*)

Planned replacement of distribution line equipment identified in deteriorated or substandard condition. This alternative is recommended as it mitigates the risk of failure of critical customer service assets and ensures a safe and reliable distribution system.

Investment Description:

This investment addresses the individual replacement or refurbishment of distribution line components when it is not economical to integrate the work into one of the large sustainment initiative projects, as described in ISD SR-12. The program comprises the replacement of the following asset types:

<u>Overhead Conductor</u>

Some types of overhead conductor (i.e., #2 ACSR and #4 ACSR) have been found to pose increased safety risks requiring modified work practices. The presence of this conductor limits Hydro One's ability to work on poles and equipment, and can pose work issues for Joint Use Partners. Replacement is based on the location and joint use status of poles which support these conductor types.

<u>Cross arms</u>

Cross arms are fastened to poles to support insulators and conductors. As these components deteriorate with age, their risk of failure increases, posing increased safety risks to the public and Hydro One personnel. System reliability is also potentially impacted.

<u>Nest Platforms</u>

Bird nests on distribution poles can potentially cause pole fires and damage equipment, impacting safety, asset condition, and system reliability. Nest platforms are constructed to allow bird nests to be relocated from distribution poles, while complying with environmental regulations protecting species at risk. The relocated nest platforms can be installed on existing poles, on taller poles, or on separate adjacent poles.

<u>Lines Regulators and Reclosers</u>

Regulators and reclosers are integral components in the operation of the distribution system. Devices requiring replacement are those which are inoperable and where maintenance is not deemed feasible. Failed or inoperable regulators and reclosers can lead to disproportionately widespread and/or extended outage impacts.

<u>Lines Transformers</u>

Some types of transformers (i.e. pole transformer units and trans closure units) have been found to be substandard as these transformers are housed in enclosures, resulting in sub-standard working clearances. These transformers are in poor condition and provide inadequate operational clearances. As a result, any work on the transformers can only be completed if they are taken out of service, which results in long outages. As these types of transformers are not currently part of Hydro One's standards, limited supplies of spare parts can also result in extended outages if they fail. These substandard transformers are replaced with pad mount transformers to current Hydro One standards.

Lines Switches

Switches are integral components in the operation of the distribution system. Overhead Air Break and Load Break switches requiring replacement are those which have failed or have operational issues that cannot be feasibly repaired. Failed or inoperable switches can lead to reduced operational flexibility as well as disproportionately widespread and/or extended outage impacts.

Sentinel Lights

Sentinel Lights are legacy equipment which provides dusk to dawn lighting for Hydro One's customers. Hydro One is contractually obligated to maintain existing installations, which may include replacing failed fixtures or poles. No new customer contracts for installation of these sentinel lights are being issued. This program also funds the removal of lights that are no longer required.

Planned replacement of these aged, deteriorated or defective assets can greatly reduce these risks of failure thereby ensuring reliability is maintained for Hydro One's customers. Depending on the types of distribution line equipment requiring replacement and the location conditions of the area, the cost of the replacement can vary. The table below outlines the proposed volume of the components to be replaced throughout the five year period. The overhead conductor replacements are project based and can vary year over year based on length and complexity of replacement.

	2018	**2019**	**2020**	**2021**	**2022**
Cross arms	1,780	1,780	1,780	1,780	1,780
Nest Platforms	15	15	15	15	15
Regulators and Reclosers	1,244	1,244	1,244	1,244	1,244
Transformers	100	100	100	100	100
Switches	60	60	60	60	60
Sentinels Lights	1,400	1,400	1,400	1,400	1,400

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, the number of storms in recent years this has not been an issue.

Result:

The line component replacement program will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets;
- Maintaining reliability of the distribution system; and
- Satisfying customer and regulatory requirements.

Outcome Summary:

Customer Focus	• Maintain reliability for customers by minimizing the number of interruptions to customers due to equipment failures. • Reduce public safety hazards of deteriorated line components.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factors which affect the costs in this investment are the following:

- The location in which the equipment is being replaced;
- Unforeseen property/easement issues; and
- Availability of required resources.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement, and coordinating with other sustainment programs where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	11.3	7.8	8.0	9.1	9.0	45.2
Less Removals	2.2	1.8	1.9	2.0	2.0	9.9
Gross Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**9.1**	**6.0**	**6.1**	**7.1**	**7.0**	**35.3**

**Includes Overhead at current rates.*

SR-11 Submarine Cable Replacement Program

Start Date:	Q1 2018	Priority:	Medium
In-Service Date:	Program	Plan Period Cost ($M):	39.1
Primary Trigger:	Safety		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One's distribution system contains approximately 11,663 submarine cables totaling about 3,300 circuit kilometers in length. These cables are used to traverse water when overhead crossings are technically or economically unfeasible.

Distribution system patrols have found that many cables are deteriorating, particularly at the shoreline. Cables that are exposed at or near the shore can be damaged by the movement of water or ice and by human activity. This damage usually takes the form of abrasion or corrosion of the protective cable armour, which can lead to neutral failure or water ingress.

Cables that are damaged or exposed at the shoreline can pose significant public safety hazards, as well as increased reliability risks.

Alternative 1: Reactive Replacement

Wait for submarine cables to fail while in service and replace them on a reactive basis. This alternative is rejected as it results in an unacceptable safety risk to the general public and employees. Contact with a damaged cable can lead to serious injury or a fatality. Emergency repairs are also more expensive as materials and resources tend to be at a premium cost.

Alternative 2: Planned Replacement (*Recommended*)

Planned replacement or refurbishment of submarine cables approaching end-of-life or demonstrating deteriorating condition. This alternative is recommended as it will mitigate the risk of failure and ensure a safe and reliable distribution system.

Investment Description:

This investment addresses the replacement or refurbishment of submarine cables that are damaged or that are exposed at the shoreline. Cables that meet these criteria are identified during distribution system line patrols. If a cable is found to pose an immediate hazard, it is immediately replaced under the "Trouble Call" program. If immediate replacement is not possible, these cables are temporarily repaired and scheduled for replacement or refurbishment. Depending on the location and extent of damage to a cable, the submarine cable may require either a sectional repair or a full cable replacement. In the case of a sectional repair, damaged locations are identified and a new section is spliced into place. However, if the cable is severely damaged, is obsolete, has exhibited poor performance, or has required repeated repairs, it is completely replaced.

This program will replace or refurbish approximately 220 to 250 submarine cable sections per year. This program also addresses the re-establishment of mechanical shoreline protection (cable covering which protects the submarine cable from deterioration caused by ice and wave damage) and the installation of warning signage for these cables.

Risk Mitigation:

Due to the significant public safety hazards associated with these defective submarine cables, these replacements are treated as a high priority and therefore no risks are foreseen with completing this replacement program as planned.

Result:

The submarine cable replacement program will result in:

- Mitigating the public safety risks of defective submarine cable; and
- Maintaining reliability of the distribution system.

Outcome Summary:

Customer Focus	• Mitigate public safety hazards from defective submarine cable. • Maintain reliability by reducing interruptions to customers from defective submarine cable.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings through planned replacements as the cost of emergency replacements is more expensive.

Costs:

The factor which affects the costs in this investment is the shoreline condition where the cable exits the water; as shoreline protection may be required for the cable.

Controllable costs have been minimized by standardizing the procedure for common activities such as equipment replacement.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	8.5	8.7	8.9	9.1	9.3	44.5
Less Removals	1.0	1.0	1.1	1.1	1.1	5.3
Gross Investment Cost	7.5	7.7	7.8	8.0	8.2	39.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**7.5**	**7.7**	**7.8**	**8.0**	**8.2**	**39.1**

**Includes Overhead at current rates*

SR-12 Distribution Lines Sustainment Initiatives

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	151.7
Primary Trigger:	Failure		
Secondary Trigger:	Reliability		

Investment Need:

Hydro One's distribution system consists of approximately 122,000 circuit kilometers of primary feeder lines across the province with approximately 17% of these feeders lines being located off-road. These off-road sections of feeders are difficult to access during power interruptions and can result in increased risk of prolonged outages.

As outlined in DSP Exhibit 2.3, Hydro One performs line patrols and preventative maintenance programs to assess the condition of its distribution feeder lines. These assessments have identified a number of concerns with the condition of the components on the primary feeders.

In addition to the condition of the distribution feeder line, there are a number of component installations that are of sub-standard design/construction based on changes over time in industry standards and do not meet current Hydro One standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks.

Alternative 1: Reactive Replacements

Wait for the distribution line equipment to fail while in service and replace it on a reactive basis. This alternative is rejected as the cost of emergency replacements is more expensive as materials and resources tend to be at a premium cost. Moreover, reactive management of the distribution line equipment will lead to increased failures resulting in risks to employee and public safety and degraded reliability for Hydro One's customers.

Alternative 2: Planned Components Replacements

Planned replacement of distribution line equipment identified in deteriorated or substandard condition, on a "like for like" component basis. This alternative is viable where an individual component of standard design on a distribution line is in deteriorated condition. However it is not ideal when multiple components are in deteriorated condition or the components are of substandard design, as individual replacement work does not allow for cost efficiencies associated with integration of replacements of assets in close proximity to each other; as well as it would require custom-engineered designs to address substandard equipment. Furthermore, this alternative would not address any accessibility concerns and would result in higher ongoing maintenance costs.

Alternative 3: Planned Lines Sustainment Initiatives (Recommended)

Planned refurbish or rebuild of entire feeders or feeder sections, when multiple components of the distribution line have been identified in deteriorated condition, in order to improve the performance of that distribution line. This alternative is recommended as it addresses the needs identified on the distribution lines in order to maintain the reliability of the distribution system in the most cost effective manner and minimize any safety risks to the public and Hydro One personnel.

Investment Description:

This investment address the refurbishment of entire feeders or feeder sections in an integrated manner to address line equipment with likelihood of failure is high. Distribution line assets deteriorate over time, taking into account the overall condition of poles, conductors and associated components; feeder sections are identified and prioritized for refurbishment or rebuild. Refurbishing or rebuilding an entire feeder section is preferred when the cost of maintaining or replacing individual components on that section becomes excessive.

There are a number projects identified under this program annually; which vary significantly in size and scope. The projects with capital investment exceeding $1 million are provided in the following table.

Year	Project Name	Net Total ($Million)
2018	City of Owen Sound Refurbishment - Part 3 of 4, *Owen Sound*	1.2
	Dundas TS M1 Rebuild Carlisle, *Dundas*	2.0
	Duart TS M6 Relocation, *Strathroy*	4.0
	Dymond TS M3 Rebuild - Part 1 of 2, *New Liskeard*	3.6
	Manitouwadge TS M2 Rebuild - Part 5 of 5, *Thunder Bay*	3.5
	Minden TS M2 - Part 2 of 2, *Minden*	2.5
	Otonabee TS M28 - Part 3 of 3, *Peterborough*	1.5
	Projects Less Than $1M	4.0
2019	Brant TS M21 Relocation, *Simcoe*	1.8
	Brockville TS 24M2-Part 5 of 5, *Brockville*	1.0
	City of Owen Sound Refurbishment-Part 4 of 4, *Owen Sound*	2.2
	Dobbin TS 20M4/6/8 Reconstruction, *Peterborough*	1.3
	Duart TS M5 Relocation, *Kent*	3.9
	Dymond TS M3 Rebuild-Part 2 of 2, *New Liskeard*	3.0
	Errington Street Rebuild—Chelmsford, *Sudbury*	1.6
	Manitoulin TS M25 Relocate, *Manitoulin*	1.1
	Martindale TS M5 Rebuild-Part 6 of 6, *Sudbury*	1.6
	Muskoka TS 30M1 Relocation-Part 1 of 5, *Huntsville*	1.0
	Owen Sound TS M24 Rebuild-Part 2 of 3, *Owen Sound*	2.8
	Tillsonburg TS 20M10/Norfolk TS M3, *Simcoe*	4.3
	Wanstead TS M2 Petrolia Tap Relocation, *Lambton*	3.0
	Projects Less Than $1M	2.4
2020	Angus 44 kV Backlot Relocate, *Barrie*	1.2
	Augasabon DS F1 & F2 Rebuild (Part 1 of 2), *Thunder Bay*	2.5
	Brant TS M22 Relocation, *Beachville*	2.0
	G3K Towerline Refurbishment, *Kirkland Lake*	1.0
	Ingersoll TS M46 Rebuild, *Beachville*	2.5
	Kent TS M16 Relocation, *Kent*	1.2
	Kleinburg TS M8, *Bolton*	2.0
	Muskoka TS M1 Relocation - Part 2 of 5, *Huntsville*	4.0
	Napanee TS M2 Relocation - Part 1 of 2, *Picton*	3.0
	Owen Sound TS M24 Rebuild - Part 3 of 3, *Owen Sound*	2.8
	Palmerston TS M1 Relocation - Part 1 of 2, *Listowel*	3.0
	Sidney TS M7 Reconductor, *Frankford*	1.3
	Weston Lake DS F1 Relocation, *Timmins*	1.0
	Projects Less Than $1M	3.4

Witness: Lyla Garzouzi

Year	Project Name	Net Total ($Million)
2021	Augasabon DS F1 & F2 Rebuild (Part 2 of 2), *Thunder Bay*	2.5
	Clarke TS M2 Relocation, *Strathroy*	2.5
	Colgan DS Inaccessible Switch 2314 Relocation, *Alliston*	1.0
	Havelock TS M2 Rebuild-Part 1 of 2, *Tweed*	2.5
	Lauzon TS M25 Rebuild, *Essex*	2.0
	Longueuil TS 26M23 Relocate, *Vankleek Hill*	3.5
	Meaford TS M1 Lower Valley Rd Rebuild, *Owen Sound*	1.5
	Muskoka TS 30M1 Relocation-Part 3 of 5, *Huntsville*	1.7
	Muskoka TS M2 Relocate, *Huntsville*	1.4
	Napanee TS M2 Relocation-Part 2 of 2, *Picton*	3.0
	Old E1R Ear Falls DS F3, *Dryden*	2.5
	Palmerston TS M1 Relocation-Part 2 of 2, *Listowel*	1.0
	Tillsonburg M1 Refurbishment, *Beachville*	2.7
	Projects Less Than $1M	6.0
2022	Forest Jura DS F1 Relocation, *Lambton*	2.0
	Geraldton Rebuild-Part 1 of 3, *Thunder Bay*	1.0
	Havelock TS M2 Rebuild-Part 2 of 2, *Tweed*	2.5
	Kirkland Lake TS G3K Relocate-Part 1 of 2, *Kirkland Lake*	4.0
	Mair Mills DS F1 Grey Rd 21 Rebuild, *Stayner*	1.0
	Muskoka TS 30M1 Relocation-Part 4 of 5, *Huntsville*	2.5
	Muskoka TS M3 Relocation, *Bracebridge*	2.0
	Palmerston TS M3 Relocation-Part 1 of 2, *Listowel*	2.5
	Picton TS M5 Rebuild (Part 1 of 2), *Picton*	3.0
	Sidney TS M7 Rebuild-Part 1 of 2, *Frankford*	3.0
	Stayner TS M2 Rebuild, *Stayner*	3.4
	Wanstead TS M1 Rebuild Alvinston, *Lambton*	2.0
	Projects Less Than $1M	4.8

Each of these projects involves equipment that is identified as a concern during the condition assessment. The refurbishment or rebuilding of entire feeders or feeder sections entails replacing all components to the present Hydro One' standard and is done in compliance with Electrical Safety Authority (ESA Reg. 22/04) requirements for new construction.

Risk Mitigation:

The risk to completion of this investment as planned is the number of major storm events which decreases the availability of qualified resources, as resources are diverted to storm restoration efforts. However, due to the lower number of major storms in recent years this has not been an issue. This investment assumes the level of major storms to be in line with historical trends.

Result:

The lines sustainment initiatives will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets;
- Maintaining the reliability of the distribution system; and
- Obtaining operational efficiencies by executing work in an integrated manner and reducing customer interruption time.

Outcome Summary:

Customer Focus	• Maintain reliability for customers by reducing the number of planned outages on distribution lines. • Improve response time by relocating off-road line segments to more accessible locations.
Operational Effectiveness	• Maintain safe and reliable operation of the distribution system by proactively addressing lines equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the existing service reliability performance of the system. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Realize cost savings by addressing multiple degrading components along a section of line as part of the same project.

Costs:

The factors which affect the costs in this investment are the following:

- The location in which the equipment is being replaced;
- Unforeseen property/easement issues; and
- Availability of required resources.

Controllable costs have been minimized by standardizing the procedure for common activities such as pole and equipment replacement.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	25.3	35.3	35.1	38.2	38.2	172.1
Less Removals	3.0	4.2	4.2	4.4	4.4	20.4
Gross Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**22.3**	**31.1**	**30.9**	**33.8**	**33.7**	**151.7**

**Includes Overhead at current rates*

SR-13 Life Cycle Optimization & Operational Efficiency Projects

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	134.0
Primary Trigger:	Failure Risk		
Secondary Trigger:	System Efficiency		

Investment Need:

Assets at the end of their expected service life are typically addressed by system renewal projects and programs that focus on like-for-like replacements. However, in some situations it is more efficient from a cost and operations perspective to address end-of-life assets by other means such as constructing supply facilities at a different location, upgrading nearby assets, or modifying the network configuration in order to eliminate the need for certain assets.

As assets reach end-of-life, the risk of failure under adverse conditions increases, which can lead to lengthy interruptions to customers and can increase the likelihood of exposing the employees and the public to safety hazards. In situations where other issues are also present, such as poor voltage, limited load transfer capability, or multiple/incompatible system voltages, it is often beneficial to address all issues through one project that upgrades or modifies the existing network configuration. As an example, converting feeders fed from an end-of-life station to a higher operating voltage results in higher load meeting capability, better power quality, and reduced line losses.

These investments provide an opportunity to achieve overall cost savings by bundling asset renewal work on stations and feeders and integrating other system capacity and operational needs under a common solution. Eliminating or combining assets reduces future operating and maintenance costs and improves operational efficiency. Other factors which may lead to addressing end-of-life assets by other than like-for-like means may include environmental factors, property issues, and incompatibility of existing assets with surrounding land uses. Project-specific information is provided in Attachment 1.

Not proceeding with this investment would result in higher expenditures, reduced productivity and inefficient operations. The issues addressed under this investment are a mix of urgent needs and good planning practices that improve overall system operations. By executing projects that simultaneously address these items over individual refurbishment or upgrade projects, overall costs are reduced and fewer resources are required.

Alternative 1: Address End of Life Assets only Through Like-for-Like Replacement

Address all end-of-life asset issues only through like-for-like replacements through other system renewal projects or programs.

This alternative is not recommended since it presents a lost opportunity to achieve overall operational efficiencies and customer benefits which can be achieved by identifying more optimal asset replacement approaches.

Alternative 2: Modify The Distribution System to Eliminate Operationally Inefficient Assets that are Nearing End-of-Life *(Recommended)*

Address specific end-of-life asset needs by means other than like-for-like where there are opportunities to reduce costs and achieve increased operational efficiencies. When stations or lines are approaching their end-of-life based on the condition of their individual components, there may be opportunities to implement system changes other than like-for-like replacement of these assets in order to achieve cost savings and long-term operational efficiencies. It may be possible to eliminate stations or consolidate line assets through voltage conversion projects, or transfers to other stations. Reduced upfront capital costs as well as future maintenance savings can be realized using this approach.

Investment Description:

A number of distribution stations are approaching their end of life. For stations where other alternatives may exist to address renewal needs, an integrated planning approach is taken. This involves assessing other potential system renewal needs in the surrounding network, capacity needs, as well as reliability and operational needs. Alternative solutions are evaluated and an optimal plan is developed which addresses all identified needs in the most cost-effective manner. In cases where stations can be completely eliminated, all existing equipment, structures and materials are removed from the property. Any necessary land remediation needed to remove contaminated soil and site restoration is also included.

To improve operational efficiency and optimize asset life cycle costs, there are several types of projects that are commonly executed.

Station Decommissioning through Voltage Conversions: One approach to remove a station from service is to convert the voltage of its feeders to match its upstream voltage. For example, to decommission a 27.6kV - 8.32kV station, the 8.32kV feeders could be converted to 27.6kV, which removes the need for the station. This approach is advantageous because it addresses stations that are near end-of-life, and improves the voltage quality and capacity of the downstream feeders.

Station Decommissioning by Constructing New Station/Feeders: Another approach used to decommission stations is to construct new stations in their place. In some cases, a new station may suffice to replace multiple stations that are near end-of-life. These projects also include the construction of new feeders to take over the loads from stations planned for decommissioning.

The most common type of project addressed under this investment is the elimination of a distribution station that has reached end-of-life by converting the station's low-voltage feeders to a higher distribution voltage. This may involve feeding the station load directly from the upstream TS supply feeder where it is feasible to do so, or by transferring it to another nearby station operating at a higher voltage. Performing a voltage conversion project may involve replacing feeder assets such as poles, transformers, primary and secondary conductors and secondary service connections, which may also be approaching end-of-life.

A listing of all proposed projects under this investment category with costs in excess of $1 million over 2018 to 2022 time frame is provided in Attachment 1. These projects are reprioritized each year based on updated condition assessment and performance data to ensure they are addressed in order of criticality. Additional funding is included in this investment for projects less than $1 million and to cover emergent needs or to coordinate system renewal needs with work initiated by other third parties such as the transmitter, land developers, municipalities, and road authorities. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as risks around property rights for poles, anchors and tree trimming required for feeder construction. For projects that require the construction of new stations, there are additional risks associated with the acquisition of new property such as the lack of a willing seller, delays due to negotiations with property owners, municipalities, and in some cases First Nation concerns. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

- Eliminated end-of-life assets to mitigate reliability, customer dissatisfaction, and safety risks;
- Improved power quality and load meeting capability of the system;
- Provide enhanced operating flexibility to mitigate customer impacts during planned outages or emergency situations;
- Improvement in overall cost effectiveness by implementing integrated solutions that address end-of-life assets, capacity, and operational needs simultaneously; and
- Reduced line losses.

Outcome Summary:

Customer Focus	• Avoided material deterioration in reliability and customer satisfaction. • Reduced outage duration by eliminating obsolete network equipment with non-standard designs/equipment. • Improved load meeting capability of the network. • Large customer needs for enhanced voltage support and other quality of power criteria addressed.
Operational Effectiveness	• Streamlined operations by eliminating multiple operating voltages and the requisite additional inventory, work methods and training needs. • Minimized cost by taking an integrated planning approach based on area supply needs. • Improved long-term operating and maintenance efficiency due to consolidating and reducing the number of system assets.
Public Policy Responsiveness	• Compliance with DSC requirements to maintain and plan the system in accordance with good utility practice. • Reduced overall environmental impact by eliminating stations where feasible.
Financial Performance	

Costs:

Construction costs for voltage conversion work can vary depending on conditions such as ground conditions, customer density, urban vs. rural, and condition of existing feeder assets. Newer lines built to present day standards can be converted to higher operating voltages at minimal cost, while older lines tend to require complete replacement and upgrading to current standards.

Costs are controlled by avoiding costly or complex design solutions where possible, by sub-contracting specialized civil work to external service providers, and by using intermediate step-down transformers where feasible to reduce the amount of line reconstruction work.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	22.7	31.8	25.3	30.6	35.9	146.2
Less Removals	2.2	4.6	2.9	1.6	0.9	12.2
Gross Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**
Less Capital Contributions						
Net Investment Cost	**20.5**	**27.1**	**22.4**	**29.0**	**34.9**	**134.0**

**Includes Overhead at current rates.*

1 **Attachment 1 – Life Cycle Optimization & Operational Efficiency Projects List of**
2 **Projects >$1M**

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-1	Barrys Bay Voltage Conversion	Convert existing 4.16 kV lines to 12.5 kV and re-supply from adjacent 12.5kV system.	Eliminate end-of-life 4.16kV distribution station and refurbish old 4.16 kV lines.	1.8	2018
LC-2	Burford DS Removal	Convert two 8.32 kV feeders to 27.6kV and remove existing Burford DS.	Eliminate end-of-life station assets.	1.5	2018
LC-3	Margach DS F3 – SD3676 Voltage Conversion	Convert 7.2 kV single-phase line section to 14.4 kV.	Eliminate end-of-life step-down transformer and line equipment.	1.4	2018
LC-4	Beaver Valley RS	Construct New 44 kV Regulating Station & Remove Existing Eugenia RS.	Eliminate End of Life Assets and potential high impact spill risk at Eugenia RS.	1.5	2018
LC-5	Carlton Place DS's Reconstruction	Construct new dual-transformer 27.6 kV station and single-transformer 8.32 kV station with MUS facilities at the site of Carleton Place Bridge DS and Edmund DS. Construct a new 27.6 kV feeder to relieve the existing Carlton Place DS #2 F2 and install step-down transformers to eliminate 4.16 kV station.	Replace end-of-life station assets at Carlton Place DS #2, Carlton Place Bridge DS, and Carlton Place Edmund DS. Improve loop feed capabilities and supply capability in the Town of Carlton Place.	5.9	2018-2019
LC-6	Dresden DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Dresden DS.	Elimination of end-of-life station assets at Dresden DS.	2.6	2018-2019
LC-7	Dundas Sydenham DS Voltage Conversion	Convert 8.32kV line section to 27.6kV. Remove existing Dundas Sydenham DS.	Eliminate end-of-life station.	2.9	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-8	Coniston Voltage Conversion	Convert 22 kV 3-wire feeder and 22 kV connected substations to 44 kV operation.	Eliminate obsolete 22 kV system voltage and allow de-commissioning of Coniston TS T1/T2 transformers which are at end of life.	3.9	2018-2019
LC-9	Town of Forest Voltage Conversion	Convert 5-4.16kV feeders to 27.6kV to match incoming supply voltage. Remove Forest Jefferson DS and Forest McNab DS.	Eliminate end-of-life station assets at Forest Jefferson DS and Forest McNab DS.	3.2	2018-2019
LC-10	Hanmer TS Feeder Development	Construct 3 new 44 kV feeders from new Hanmer TS DESN.	Elimination of existing 44 kV off-road line sections fed from Martindale TS which are at end of life.	4.9	2018-2019
LC-11	Lucan Market DS Voltage Conversion	Convert two 4.16 kV feeders to 27.6 kV operation, install 2 x 2.5MVA 27.6-8kV step down transformers to replace existing 5MVA transformers at Lucan Market DS.	Eliminate end-of-life station assets at Lucan Market DS.	3.3	2018-2019
LC-12	Warkworth DS Removal	Offload station by reconfiguring and extending existing feeders from other adjacent stations, and remove Warkworth DS.	Eliminate end-of-life station assets at Warkworth DS.	2.9	2018-2019
LC-13	Grand Bend Downtown Voltage Conversion	Convert loads in downtown Grand Bend currently fed at 8.32 kV to 27.6 kV supply.	Eliminate end-of-life 8.32 kV line assets and reduce line congestion in main business section of Grand Bend.	1.3	2019
LC-14	Brookside DS Removal	Off load Brookside DS by building and reinforcing feeder ties to adjacent stations. Remove Brookside DS.	Eliminate end-of-life station assets at Brookside DS.	1.9	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-15	Drumbo DS Voltage Conversion	Convert two 8.32 kV feeders to 27.6kV to match incoming supply voltage and remove existing Drumbo DS.	Eliminate end-of-life station assets at Drumbo DS.	2.0	2019-2020
LC-16	Lily Lake DS Removal	Off load Lily Lake DS by building and reinforcing feeder ties to adjacent stations including some limited voltage conversion. Remove Lily Lake DS.	Eliminate end-of-life station assets at Lily Lake DS.	3.3	2019-2020
LC-17	Rondeau DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Rondeau DS.	Eliminate end-of-life station assets at Rondeau DS.	1.7	2019-2020
LC-18	Thorold Turner DS Voltage Conversion	Replace Thorold Turner DS with padmount transformers.	Eliminate end-of-life station.	1.0	2019-2020
LC-19	Wallaceburg DS Voltage Conversion	Convert 3-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Wallaceburg DS.	Eliminate end-of-life station assets at Wallaceburg DS.	1.7	2019-2020
LC-20	Devlin DS Rebuild and Voltage Conversion	Refurbish Emo DS and Devlin DS and replace existing 44-12.5 kV transformers with 44-25 kV units. Convert 12.5 kV line sections to 25 kV operation.	Replace end of life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.0	2020
LC-21	Blind River Voltage Conversion	Convert 12.5 kV feeder to 25 kV to match incoming supply voltage & remove Blind River DS.	Eliminate end of life station assets including obsolete single phase transformers.	1.0	2020
LC-22	Kemptville Area System Upgrades	Upgrade Kemptville West DS from 5 MVA to 7.5 MVA and add new feeder position.	Meet forecast load growth in the Town of Kemptville.	4.2	2020-2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-23	Maxville Area System Upgrades	Off load Maxville Prince DS by converting feeders from 4.16 kV to 8.32 kV and transferring to Maxville George DS.	Eliminate end-of-life station assets at Maxville Prince DS and eliminate 4.16 kV system in Town of Maxville.	4.2	2020-2021
LC-24	Prescott Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2020-2021
LC-25	Wardsville DS Voltage Conversion	Convert 8.32 kV feeder to 27.6kV to match incoming supply voltage and remove existing Wardsville DS.	Eliminate end-of-life station assets at Wardsville DS.	1.1	2020-2021
LC-26	Alexandria Area System Upgrades	Upgrade Alexandria Industrial DS from 5 MVA to 7.5MVA. Remove Alexandria – Margaret DS, East Boundary DS, Kenyon West DS and transfer loads to adjacent DSs. Convert the town 4.16kV feeders to 8.43kV.	Eliminate end-of-life station assets as Kenyon West DS, provide loop feeds for single contingency backup of DS's in the town of Alexandria.	3.8	2021
LC-27	Anderdon DS Voltage Conversion	Convert 2-8.32kV feeders to 27.6kV to match incoming supply voltage, and remove Anderdon DS.	Eliminate end-of-life station assets at Anderdon DS.	1.5	2021
LC-28	Town of Elliot Lake Station Upgrades	Replace Mississauga DS T2 transformer with larger unit and add second transformer at Porridge Lake DS.	Facilitate the elimination of Elliot Lake DS which is at end-of-life and improve load transfer capability in Town of Elliot Lake.	3.5	2021
LC-29	Vanastra DS Voltage Conversion	Convert 8.32 kV lines to 27.6 kV to match incoming supply voltage and install step-down transformers.	Eliminate Vanastra DS which is at end of life.	2.2	2021

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
LC-30	Berwick-Finch Area Upgrades	Offload Crysler DS F2 onto Casselman DS F1 by reinforcing feeder ties.	Crysler DS F2 feeder load is approaching planning guideline.	4.2	2021-2022
LC-31	Brockville Distribution System Upgrades	Upgrade various distribution feeder sections within the Town of Brockville.	Replace end-of-life distribution line assets, including direct buried cable, and eliminate back lot construction.	4.2	2021-2022
LC-32	Chesterville Area Upgrades	Add a second 5 MVA 44-8.32 kV transformer at Frood DS and one with additional feeder. Convert 5 existing 4.16 kV feeders to 8.32kV and remove Chesterville DS#2 & Brennen DS.	Eliminate end-of-life station assets at Chesterville DS #2 and Brennen DS and standardize on a single voltage 8.32 kV in the Town of Chesterville.	4.2	2021-2022
LC-33	Ivy Lea Area System Upgrades	Upgrade Ivy Lea DS station capacity.	Provide load relief to transformer loaded above planned load limit.	4.2	2021-2022
LC-34	Russell Area System Upgrades	Offload Russell DS to the neighbouring stations and Remove Russell DS.	Eliminate end-of-life station assets at Russell DS.	4.2	2021-2022
LC-35	Smiths Falls System Upgrades	System upgrades to allow removal of Smith Falls James DS.	Address end-of-life station assets and reliability risks due to lack of MUS facilities.	4.2	2021-2022
LC-36	Actons Corners Area System Upgrades	Implement system upgrades as per recommendations of pending study.	Eliminate end-of-life system assets and ensure reliable supply.	4.2	2022
LC-37	Sleeman DS Rebuild and Voltage Conversion	Rebuild Sleeman DS at a new location and convert 12.5 kV line sections to 25 kV.	Replace end-of-life station assets including obsolete single phase transformers and standardize to one distribution voltage of 25 kV.	4.4	2022

SR-14 Advanced Meter Infrastructure Hardware Refresh

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	79.9
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Failure Risk		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. There are several factors that can trigger the need to upgrade these meters; some of the key factors are listed below:

- Hydro One Distribution is accountable, based on the market rules, to upgrade wholesale meter installations to a retail revenue meter when customers decide to become a retail customer of Hydro One Distribution at seal expiry;
- Hydro One Distribution has acquired non-standard meter installations due to a boundary change or the outright acquisition of an LDC;
- Hydro One Distribution has a population of 600V self-contained meters that are being replaced with inherently safer 120V transformer rated meters;
- Hydro One Distribution is required by the Distribution System Code, to upgrade existing customer's demand meters to interval meters when the average annual monthly peak demand is equal to or greater than 50 kW. There is also a requirement to install interval meters for customers who exceed 150,000 kWh of energy consumption per year; and
- Hydro One Distribution will require to replace smart meters once these meters reach the end of expected service life.

Alternatives:

No alternatives are considered, since this program represents the minimum level of work to satisfy Hydro One Distribution's operational requirements. Replacement of meters is critical to maintaining a reliable source of billing settlement data.

Investment Description:

This investment provides planned upgrades to address meters that no longer meet current standards, are obsolete, have reached end of service life; and to address regulatory requirements imposed by the Distribution System Code. The work includes, but is not limited to the following:

- Upgrade wholesale meter installations or acquired non-standard retail meter installations to Hydro One Distribution's current retail revenue meter standard;
- Upgrade 600V self-contained meters, with expired seals, with new 120V meters. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, allows Hydro One Distribution to meet expired seal obligations, eliminates a reliance on a single source supply as like-for-like replacements are not readily available on the market, and assists in standardizing inventory;
- Upgrade existing customer's meters to interval meters or demand meters when the energy consumption exceeds the thresholds set out in the Distribution System Code; and
- Replace smart meters which have reached the end of their expected service life. Smart meters have a manufacturer service life of 15 years, therefore, meter replacements will commence in 2021 with 3,621 replacements and another 206,119 replacements in 2022. A similar level of replacements will be required beyond the planning period.

The forecast of the number of meters requiring replacement and upgrade annually over the five year period is provided in the table below. The capital investment of each meter upgrade is below $1 million.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Meter Upgrades/Replaced	341	341	341	4,134	206,632

Risk Mitigation:

The risks to completion of this investment as planned are the availability of the vendor to manufacture and deliver the meters in a timely manner, and the availability of qualified resources to perform the volume of replacements required. These risks are mitigated by providing procurement forecasts upfront to the vendor, maintaining ongoing discussions with vendor regarding future product supply, and managing resources with option to hire temporary staff as required.

Result:

This meter upgrade program will result in:

- Ensuring timely replacement of meters,
- Complying with regulatory requirements, and
- Ensuring a continue reliable source of billing settlement date for customers.

Outcome Summary:

Customer Focus	• Maintain billing accuracy and customer confidence by ensuring reliable meter performance.
Operational Effectiveness	• Maintain reliable operation of the meter and meter infrastructure network by proactively replacing equipment.
Public Policy Responsiveness	• Comply with the OEB Distribution System Code Section 2.10 "Estimated Billing" requirement for no more than 2 estimated meter reads per year and Section 7.11 "Billing Accuracy" requirements.
Financial Performance	• Avoid the cost of manual meter reading through timely replacement of meter and network equipment.

Witness: Lyla Garzouzi

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The accessibility conditions of the area in which the meters are being replaced. Accessing off road locations or replacing a meter on a lake cottage can be more costly due to the use of specialized equipment.

Controllable costs have been minimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	0.0	0.0	0.0	1.4	78.5	79.9
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	**0.0**	**0.0**	**0.0**	**1.4**	**78.5**	**79.9**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**0.0**	**0.0**	**0.0**	**1.4**	**78.5**	**79.9**

**Includes Overhead at current rates*.

SS-01 Remote Disconnection / Reconnection Program

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	28.5
Primary Trigger:	System Efficiency		
Secondary Trigger:	Customer Service Requests		

Investment Need:

Hydro One currently owns, operates, and maintains approximately 1.3 million retail revenue meters. From time to time, there is a need to have power to these meters disconnected and/or reconnected as a result of customer non-payment and vacant premises.

Hydro One makes every effort to work proactively with customers to address billing issues and adheres closely to all steps mandated in the OEB Distribution System Code. Disconnection is only considered as a last resort; as customers rely on their power and understandably become upset if a decision is made to disconnect power. Hydro One makes every effort to take swift action in the reconnection of power for customers in order to reestablish important electrical services to their home or business.

Hydro One currently implements a manual disconnection and reconnection process, requiring at least two trips to the customer premises. These disconnection and reconnection activities cause between 10,000 and 21,000 on-site visits per year. The costs and associated risks of this manual process can be avoided with the utilization of meters that have the functionality to execute remote disconnection and reconnection.

Alternative 1: Continue Manual Disconnections/Reconnections

Continue to manually disconnect and reconnect customer meters when required in accordance with Section 4.2 of the OEB Distribution System Code. This alternative is rejected as it will not result in improving the customer experience or achieving operational efficiencies.

Alternative 2: Remote Disconnections/Reconnections *(Recommended)*

Install new meters with remote disconnection and reconnection functionality at customer sites where non-payment and/or vacant premises situations exist. This alternative is recommended as it will reduce the number of visits to customer premises resulting in operational efficiencies, and improve customer experience by providing a faster response time for disconnection and reconnection requests. Active and timely actions to address customers in arrears also assists customers in staying current with their invoices and reducing bad debt expenditure.

Investment Description:

This investment addresses the replacement of existing meters at customer premises with new meters capable of remote disconnection and reconnection functionality. Meter replacements will be identified for replacement when disconnection required based on assessment of customer accounts in arrears due to non-payment and/or customer premises with noted vacancy. These replacements are to be rolled out in stages as work orders are authorized and appropriately approved for action of disconnection. The table below is an annual forecast of meter replacements.

	2018	**2019**	**2020**	**2021**	**2022**
Number of Meter Replacements	11,875	11,500	11,125	10,750	10,375

Once the new meters are installed, the actual execution of the reconnection (or disconnection) is accomplished within a few minutes after the customer request has been authorized and appropriately approved for action thereby reducing lost revenue for unbilled power, and providing improved customer service through faster response time.

Risk Mitigation:

The risks to completion of this investment as planned are the availability of the vendor to manufacture and deliver the meters in a timely manner, and the accessibility of the meters required to be replaced. These risks are mitigated by providing procurement forecasts upfront to the vendor, maintaining ongoing discussions with vendor regarding future product supply, and managing coordination with resources required to gain access.

Result:

This remote disconnection/reconnection program will result in:

- Reducing the number of required visits customer premises thereby delivering operational efficiency, and potentially avoiding approximately $4.5 million in costs annually arising from on-site reconnections and disconnections and the safety risks related to driving hours; and
- Improving the customer's experience by providing a faster disconnection or reconnection response time.

Outcome Summary:

Customer Focus	• Improve customer experience by providing a faster response time for disconnection and reconnection requests.
Operational Effectiveness	• Increase operational effectiveness by executing the disconnection/reconnection process in a more efficient manner. • Reduce employee safety risks related to driving hazards by avoiding travel to customer premises.
Public Policy Responsiveness	• Comply with the OEB Distribution System Code Section 4.2 regarding disconnection and reconnection process.
Financial Performance	• Avoid the cost arising from on-site reconnection/disconnection at customer premises by installing new meters with remote reconnection/disconnection functionality.

Costs:

The factors which affect the costs in this investment are the following:

- The cost of material and term of procurement contracts; and
- The accessibility conditions of the area in which devices are being replaced. Accessing off road locations to replace network devices can be more costly due to the use of specialized equipment.

Controllable costs have been minimized through standardization of metering device purchasing specifications and issuance of vendor contract to secure unit pricing for procurement of materials.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	5.9	5.9	5.8	5.8	5.7	29.1
Less Removals	0.1	0.1	0.1	0.1	0.1	0.6
Gross Investment Cost	**5.8**	**5.8**	**5.7**	**5.6**	**5.6**	**28.5**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**5.8**	**5.8**	**5.7**	**5.6**	**5.6**	**28.5**

**Includes Overhead at current rates.*

SS-02 System Upgrades Driven by Load Growth

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	190.0
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

Over time, new customers connect to the system, and load growth occurs as a result. This also occurs due to increased loading at some existing customers who may increase their service sizes. This places additional stress on the elements of the distribution system. Increases in distribution station and feeder loading can lead to system elements operating at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load.

In accordance with Section 3.3 of the Distribution System Code ("DSC"), Hydro One Distribution plans and executes enhancement projects on its distribution system to improve system operating characteristics and relieve system capacity constraints. This investment covers major system upgrades that are needed in response to load growth.

Investments with a gross cost less than $300,000 are normally included in either the Distribution System Modifications (ISD SS-05) or Demand Investments (ISD SS-04) capital programs.

The capability of the Hydro One distribution system to accommodate forecast loading needs is determined through the following four main activities:

1. load versus capability screening at the station and feeder levels;
2. planned feeder studies (six-year cycle studies);
3. system impact assessments for large new load connections; and
4. assessment of field and customer identified issues related to power quality or other operating concerns.

Load versus system capability and planned feeder studies (six-year cycle studies) are the main pro-active planning activities carried out to assess the capability of Hydro One's system to accommodate existing and forecast needs. These activities take into account the capability of the network to meet load needs based on normal anticipated load growth. Load growth rates vary for different segments of the system. For example, the growth rates can differ significantly between urban and rural segments. Normal load growth is determined locally within the system based on historical trends, known or planned development in an area, and information from local municipalities including official plan documents and long-term population projections. In some cases, local power quality or reliability issues may be identified by field staff or customers due to specific local loading issues or changes that develop over time and may need to be addressed through system upgrades. If these issues cannot be accommodated under the Demand Investments capital program (ISD SS-04) then a major capital project may be required.

For all new load connections or customer upgrades above 500 KVA, and for new subdivisions with more than fifteen lots, a distribution system impact assessment is conducted in order to determine the impact of the proposed load with respect to equipment ratings, voltage and protection criteria, and planning guidelines. Where planning criteria will be violated, system upgrades may be required. Where an upgrade is required in order to meet the specific loading needs of one individual customer, a customer contribution may be required based on a discounted cash flow evaluation of future revenues and costs.

For distribution feeders, planning guidelines for load-ability have been established based on feeder voltage level. Planning guidelines are used to conduct high-level screening of system capability to maintain loading within equipment ratings, meet system voltage and protection needs, and ensure a reasonable degree of operating flexibility and efficiency. Planning guidelines are based on typical feeder topology and lengths. In some parts of Hydro One's distribution system where feeder distances are significantly long or load centers are far from the supply station, technical considerations such as voltage and system protection needs restrict maximum feeder loading to values, which are less than the planning guidelines.

Where major new capacity upgrades are deemed necessary through load screening or other means, Hydro One uses an integrated planning approach to identify and develop the optimal system development plans for a specific area. This involves assessing other potential system needs in the surrounding network from the perspective of capability, performance, operability, sustainment, and efficiency/effectiveness. Once the full long-term needs for the system are determined, integrated solutions are identified to ensure the long term viability of the network in the most cost-effective manner.

Alternative 1: Allow System Assets to Become Overloaded

Wait until overloaded assets reach critical values such that customers are experiencing significant power quality issues, or a material decrease in reliability is observed.

This alternative was rejected since it does not satisfy the DSC requirement for a distributor to enhance its system in response to normal load growth. Also, due to the long lead times needed to implement effective solutions, there would be significant customer dissatisfaction due to on-going power quality issues and reduced reliability.

Alternative 2: Upgrade System to Meet Normal Load Growth (Recommended)

Pro-actively monitor system loading, conduct system studies for forecast new load connections and develop appropriate investment plans to address system needs based on forecast load.

The recommended plan satisfies section 3.3 of the DSC, which requires distributors to plan and expand their systems in response to normal load growth. Identifying and implementing major projects to maintain loading on assets within design ratings ensures acceptable delivery voltage is provided to customers, that reliability is maintained at acceptable levels, and that system assets are not exposed to undue stress.

Investment Description:

System load growth over the next five years is expected to be in line with recent historic growth patterns. Approximately 90,000 new customer connections and 27,000 service upgrades are forecast for the 2018-2022 time period. Cancellation of about 34,000 existing services is also anticipated for an overall increase in customers of 56,000 or 4.4% of the existing customer base over the next five years.

The majority of growth and new customer connections are expected to occur in Hydro One's urban service territories which border major urban centers including the City of Ottawa, City of Kingston, northern York and Peel Regions, Durham Region, and the City of Hamilton. For the remainder of Hydro One's service territory which is mostly rural in nature, load growth and new customer connection activity is expected to be in line with historic rates which are generally lower.

Proposed investments to address load growth include station upgrades, feeder upgrades and modifications, new feeders, construction of new distribution stations and new voltage regulating stations, and conversion of feeders to higher voltages. Also included are feeder development projects in accordance with recommendations of Regional Infrastructure Plans. A list of all planned system upgrades in excess of $1 million along with their proposed timing is provided in Attachment 1. Additional funding is included to cover projects less than $1 million as well to cover emergent needs due to unforeseen customer connections or upgrades.

There are a variety of ways to relieve overloaded equipment. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

<u>Feeder Reinforcement</u>: One common solution is to redistribute load through reinforcement projects. In urban areas, this can entail upgrading or creating new radial loops. These projects focus on optimizing load distribution by reconfiguring existing feeders to enable load transfers between phases, and between different feeders. By extending feeders, installing new phases and tie points, and updating feeder protections, lightly loaded feeders can offload heavily loaded sections.

<u>Station Upgrade</u>: Station upgrade projects are executed in areas where the existing configuration cannot be utilized to offload equipment that has reached its planned loading limit. Instead, additional capacity must be added to the system. Station upgrades involve an increase in capacity to existing stations by upgrading transformer sizes; installing additional transformers; increasing the station's secondary voltage (voltage conversion at the station); or installing fan monitoring to cool station transformers. These projects also include adding new feeder positions at the station to increase the number of available feeders.

<u>Construct New Station</u>: In some situations, constructing a new station is more effective from a cost and operating perspective than upgrading an existing station. In these cases, a new distribution station is installed and incorporated into the distribution system. New feeders are also used to provide additional capacity to areas that are overloaded. These feeders may be built to compliment the construction of a new distribution station.

<u>Voltage Conversion</u>: To increase equipment ratings and capacity, feeders may also be converted to higher voltage levels. These upgrades may coincide with a station voltage conversion or may involve a reconfiguration with nearby feeders that operate at higher voltage levels.

Risk Mitigation:

The main risks concerning project execution are real estate/property rights, shortage of qualified labour, customer delays, and delays in finalizing development plans.

Construction of new stations requires acquisition of new property and is subject to delays due the lack of a willing seller, negotiations with property owners, municipalities, and in some cases First Nation concerns. Construction or upgrading of feeders requires occupancy rights on road allowances or private property, as well as cutting rights and anchoring easements on private property. Delays, or the inability in obtaining these rights, can lead to the need for re-design, or route alterations. In some cases, road authorities may have coinciding plans for road widening or other construction, which need to be coordinated with new pole locations resulting in delays to line construction work. These risks are mitigated by providing appropriate lead times during the design and estimating stages to allow sufficient time for obtaining necessary property rights. For new station or station upgrade work, Hydro One has recently implemented a new project planning approach where any new property needed will be determined and acquired prior to commencing engineering/design work.

Execution of the proposed station and feeder construction projects identified in this investment driver requires the coordinated efforts of multiple technical and engineering disciplines some of which are highly specialized. Lack of available resources in these specialties can lead to project delays. These risks are mitigated by establishing appropriate project time lines in conjunction with internal and external service providers to reflect available resources for design and construction.

Projects that are being driven by specific customer requests or by specific development needs are also subject to delays due to changes in the customers' or developers' timing.

Projects are reprioritized each year as new loading information and updated forecasts become available to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement due to unforeseen load growth or specific customer requests. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

Result:

System Upgrades Driven by Load Growth will result in:
- Ensuring there is adequate capacity within the distribution system to meet existing and forecast customer load needs;
- Maintaining acceptable Power Quality throughout the distribution system;
- Ensuring the safe and reliable operation of the distribution system;
- Reducing the risk of lengthy customer outages caused by failure or malfunction of overloaded assets;
- Balancing loads to allow for additional customer connections and to improve voltage and power quality;
- Reducing line losses; and
- Providing additional supply options to relieve overloaded feeders and enable future load growth and customer connections.

Outcome Summary:

Customer Focus	• Meet load needs of existing and new customers. • Ensure acceptable delivery voltage and other quality of power criteria are provided to customers. • Improve customer reliability.
Operational Effectiveness	• Maintain safe and effective operation of the distribution system. • Minimize overall costs by taking an integrated planning approach based on an overall assessment of area supply needs.
Public Policy Responsiveness	• Meet requirements of the Distribution System Code to plan the system to accommodate reasonable forecast load growth. • Comply with equipment standards which include Renewable Energy enabling technologies.
Financial Performance	

Costs:

Costs are primarily affected by design requirements and conditions of construction. Hydro One uses three main styles for new station construction based on rural vs. urban as well as operating requirements. The optimal design solution is based on a number of factors including property availability, capacity requirements, operational needs, compatibility with surrounding land uses, as well as environmental mitigation needs.

Feeder construction costs can vary widely depending on conditions such as ground type (soil vs. rock), tree density where right-of-way clearing or expansion is required, underground vs. overhead, and whether it is green field construction versus upgrading or overbuilding of existing lines. Costs are controlled by avoiding costly or complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions) -	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	47.6	55.9	46.6	34.5	24.6	209.2
Less Removals	4.4	4.5	3.6	1.8	2.0	16.3
Gross Investment Cost	**43.2**	**51.4**	**42.9**	**32.7**	**22.6**	**192.9**
Less Capital Contributions	2.8					2.8
Net Investment Cost	**40.4**	**51.4**	**42.9**	**32.7**	**22.6**	**190.0**

**Includes Overhead at current rates.*

Attachment 1 – System Upgrades Driven by Load Growth

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-1	Cumberland DS F4 Development	Extend the lightly loaded F4 feeder from Cumberland DS to meet with the more heavily loaded F2.	Provide a loop feed for the Cumberland urban load area and meet future load needs.	1.2	2018
LG-2	Devlin DS F1 3 Phase Upgrade	Upgrade 3 km of two-phase and 1.5 km of single-phase line to three-phase along Highway 613.	Address single phase line loading above Planning Guidelines.	1.0	2018
LG-3	Kleinburg TS M6 Mayfield Rd Line Extension	Extend 27.6 kV along Mayfield Road, for approximately 4 km, from Airport Rd to Dixie Road.	Improve supply efficiency and reliability and provide capability to supply future loads along Mayfield Road in the Town of Bolton.	1.0	2018
LG-4	Orangeville TS M3 - Mayfield West Line Extension	Extend 44 kV feeder from Chinguacousy Rd, east along Old School Road, for approximately 6 km.	Introduction of 44kV to the Mayfield West area, to facilitate connection of anticipated industrial loads, and to construct a future Old School Road DS.	1.8	2018
LG-5	New Bradford North DS	Construct new 44-27.6 kV DS, as well as associated feeders.	To meet forecast residential and commercial load growth in the Town of Bradford West Gwillimbury.	5.0	2018-2019
LG-6	Caledonia TS M3 Extension	Convert 7.5 km of 4.16 kV line to 27.6kV and transfer load from Jarvis TS M3 to Caledonia TS M3.	Relieve overloaded step-downs and improve reliability to Six Nations.	1.1	2018-2019
LG-7	Alfred DS F2 Feeder Upgrades	Upgrade 6 km of single-phase line to three-phase, balance loads between phases, and between F1 and F2 feeders.	Single phase line section loaded above planning guideline.	2.4	2018-2019
LG-8	Cameron DS Feeder Improvements	Construct new F2 feeder out of Cameron DS and upgrade existing single phase line to three phase along Monarch Road and Hwy 35.	To meet forecast residential load growth in west part of the Town of Lindsay.	1.4	2018-2019
LG-9	Armitage TS M22 Extension	Extend M22 feeder by double circuit with existing M12 feeder, for approximately 6 km. Transfer Wesley DS from M12 to M22.	Provide load relief to Armitage TS feeder M12 which is loaded beyond planning guidelines.	2.0	2018-2019

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-10	City of Owen Sound Tie-Line Reinforcement	Construct new 4.16 kV tie-lines between 24th St West DS and 2nd Ave West DS, and between 6th Street East DS, and 2nd Ave East DS.	To provide loop feeds for single-contingency back up of DS transformers which do not have MUS facilities.	1.3	2018-2019
LG-11	Enfield TS Feeder Development	Construct two new 44 kV feeders out of Enfield TS consisting of 18 km of new feeder line.	To meet forecast load growth in Durham Region.	7.6	2018-2019
LG-12	Grand Bend DS F3 Voltage Conversion	Convert existing 8.32 kV feeder to 27.6 kV and connect to Grand Bend East DS F2 feeder.	To address substandard voltage being experienced by customers along the Lake Huron shoreline south of Grand Bend.	2.4	2018-2019
LG-13	Kirkland Lake Voltage Conversion – Part 1	Rebuild Goodfish DS and replace 44-4.16 kV transformer with a 44-12.5 kV unit. Convert Goodfish DS F8, F9, F10 feeders from 4.16 kV to 12.5 kV.	Meet future load needs in the Town of Kirkland Lake and eliminate obsolete metalclad switchgear at Goodfish DS.	4.8	2018-2019
LG-14	Leamington TS Feeder Development	Build 8 new 27.6 kV feeders from Leamington TS, transfer load and DG from Kingsville to Leamington TS, and partial 8.32 kV DS conversion to 27.6 kV.	Meet future load needs in the towns of Kingsville and Leamington consistent with Supply to Essex County Transmission Reinforcement (SECTR) work.	3.7	2018-2019
LG-15	Manotick DS Feeder Development	Extend new F3 feeder to off-load existing F1 feeder and to connect to new residential subdivisions.	To connect new residential subdivisions in Manotick to new F3 feeder.	2.6	2018-2019
LG-16	Stouffville 10th Line DS New T3 & Feeder	Construct new DS with 2 x 44 - 27.6 kV and 1 x 44 - 8.32 kV transformer.	Replace existing end-of-life 8.32 kV T1 station assets and add more capacity to meet the load growth in the Town of Stouffville.	6.6	2018-2019
LG-17	Town of Shelburne Voltage Conversion	Convert 4.16 kV feeders to 8.32 kV and rebuild Shelburne DS as a single-transformer station, 44-8.32kV. Remove existing T1 and T2 transformers.	Increase transformer and feeder capacity at Shelburne DS to meet forecast load growth.	8.4	2018-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-18	Twelve Mile Bay DS - New Station & Feeders	Construct a new 44-12.5 kV station including 1 km of new 44 kV line with 12.5 kV underbuild, and install 11 km of new three-phase submarine cable in Georgian Bay to connect the new station to the Honey Harbour DS F1 feeder.	Provide load relief to Foots Bay DS which is loaded above its PLL, and to the Honey Harbour DS F1 feeder which does not meet system protection requirements.	4.0	2018-2019
LG-19	Beckwith DS F3 Feeder Development	Extend new Beckwith DS F3 feeder to off-load F1 and T1 transformer.	Relieve T1 overloading and create a three-phase loop feed for urban customers.	1.8	2019
LG-20	Crilly DS Replacement and Transformer Upgrade	Construct new Crilly DS 2 km from existing DS site. New Crilly DS will be supplied from Hydro One 115 kV circuit.	Address overloaded transformer and eliminate non-standard supply from privately owned generating station bus.	6.7	2019
LG-21	Kirkland Lake Voltage Conversion-Part 2	Replace 44-4.16 kV transformer at Woods DS with a 44-12.5 kV unit. Convert Woods DS F5, F6, F7 feeders from 4.16 kV to 12.5 kV.	To meet future load needs in the Town of Kirkland Lake.	2.0	2019
LG-22	Manotick DS F3 New Feeder	Add new feeder position and underground egress to connect new F3 Feeder	To meet forecast residential load growth in the Village of Manotick	1.9	2019
LG-23	Margach DS F3 Voltage Conversion - SW676	Extend Keewatin DS feeder F2 for 3.5 km to off-load part of the Margach DS F1 load onto Keewatin DS F2.	Provide load relief to overloaded step-down transformer.	1.4	2019
LG-24	Muskoka TS M5 x M1 Feeder Tie	Extend the Muskoka TS M5 feeder for 14 km from Ullswater DS to the village of Rosseau by overbuilding existing 12.5 kV feeders with 44 kV.	To facilitate off-loading Parry Sound TS through a load transfer to the Muskoka TS M1 feeder and to create a 44 kV loop feed around Lake Rosseau.	5.3	2019
LG-25	Rockland DS T2 Transformer	Install a second transformer at Rockland DS.	Provide load relief to existing T1 transformer and meet forecast load growth.	2.3	2019
LG-26	Barrie TS - Construct New Feeders	Construct 8 km of New 2-circuit 44 kV Line from Barrie TS to Salem Road.	To meet forecast load needs of InnPower embedded LDC.	2.6	2019-2020
LG-27	Caledonia TS New Feeders	Construct 6 km of new 27.6 kV feeders from Caledonia TS.	Relieve Existing Feeders which are loaded above planning guideline.	4.3	2019-2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-28	Dundas TS #2 New Feeders	Construct 2.5 km of new feeders from Dundas TS#2. Construction will be done across the Niagara Escarpment and through a subdivision.	To provide load relieve to Dundas TS T1/T2 DESN.	6.7	2019-2020
LG-29	King City DS - New Station & Feeders	Construct a new 44-13.8kV DS. Build feeder ties with existing 13.8kV feeders from Eversley DS, and balance load between feeders / stations.	Provide a second 13.8 kV source of supply for King City to enable loop feeds and meet future load growth.	4.6	2019-2020
LG-30	New Old School DS	Construct a new 44-27.6kV DS. Construct 27.6kV feeders and tie to Snelgrove DS and Kleinburg TS M6.	Relieve capacity issues at Snelgrove DS, and provide a second 27.6kV source to improve loop feed supply.	7.0	2019-2020
LG-31	Town of Dundalk Voltage Conversion	Construct a new 44-8.32kV DS. Convert existing 4.16kV loads within the town of Dundalk to 8.32 kV, and remove existing 44-4.16kV transformer.	Provide increase station and feeder capacity to meet forecast load growth in Town of Dundalk.	9.5	2019-2021
LG-32	Greely DS F1 Feeder Development	Extend F1 feeder from Greely DS to offload existing feeders.	To meet forecast load growth in south Ottawa.	1.5	2020
LG-33	Kirkland Lake Voltage Conversion-Part 3	Convert Kirkland Lake DS #1 F1, F2, F3 feeders from 4.16 kV to 12.5 kV and re-supply from Goodfish DS and Woods DS. Remove Kirkland Lake DS #1.	Meet future load needs in the Town of Kirkland Lake and eliminate Kirkland Lake DS #1 which has obsolete switchgear and is located inside the Kirkland Lake TS yard.	2.8	2020
LG-34	Midhurst Wilson DS F2 Extend to Doran Rd	Overbuild 6.5km of existing 8.32 kV line with new 27.6 kV feeder from Wilson Road to Doran Road.	To meet future residential subdivision growth in the north-east Midhurst Area (Midhurst Secondary Plan – Neighbourhood 2).	2.2	2020
LG-35	Midhurst Wilson DS F1 Extend to Dobson Rd	Extend Midhurst Wilson DS 27.6 kV feeder for 3.5 km to Dobson Rd by converting existing Grenfel DS F2 feeder from 8.32 kV to 27.6 kV.	Address forecast overloading of Grenfel DS F2 feeder due to residential subdivision load growth.	2.2	2020
LG-36	Perth Area Upgrades	Reconstruct station egress's with higher capacity underground cable.	Provide back feed capability for single contingency station transformer outage.	2.0	2020

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-37	Macville DS - New 27.6kV Station	Extend Kleinburg TS M26 44 kV feeder for 2km and construct a new 44-27.6kV DS.	Provide Additional DS capacity to meet forecast load growth in the Town of Caledon.	3.7	2020-2021
LG-38	Wikwemikong DS & Line Work	Build a 15 kV 44 kV feeder extension by overbuilding existing a 12.5 kV line and construct a new 44-12.5 kV station. Upgrade an additional 3 km of existing 12.5 kV line to double-circuit.	To meet forecast load growth at Wikwemikong First Nation on Manitoulin Island.	6.5	2020-2021
LG-39	Dunchurch DS F2 - Extend to Magnetewan	Upgrade 10 km of existing single-phase line to three-phase and build 1 km new line to extend Dunchurch DS F2 feeder to Town of Magnetewan.	Provide load relief to Burks Falls DS F2 feeder which is loaded above planning guidelines and does not meet system protection criteria.	2.8	2021
LG-40	Fairbanks Lake Line Upgrade	Upgrade 2.6 km existing single-phase line to three-phase and build 8.7 km of new three-phase line.	To Address Substandard Feeder Protection on existing Whitefish DS F1.	2.5	2021
LG-41	Kleinburg TS M26 extension to Mayfield West	Extend Kleinburg TS M26 to Mayfield West (approximately 12 km).	Provide load relief to Pleasant TS M21 feeder based on forecast loading.	3.2	2021
LG-42	Lively DS F2 SW142 Upgrade Black Lake Road	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.4	2021
LG-43	Mar DS – New Station	Construct a new 44-12.5 kV station and 2 km of new 12.5 kV feeders.	Provide load relief to Colpoys Bay DS which is loaded above the transformer Planned Load Limit (PLL).	3.0	2021
LG-44	Ancaster West DS Transformer Upgrade	Upgrade Ancaster West DS transformer from 5 MVA to 7.5 MVA.	Provide DS Capacity to meet forecast load growth.	2.0	2021-2022
LG-45	Brockville 44kV System Upgrades	Extend Brockville M7 and Morrisburg M24 feeders to off load B1R and M5 feeders.	Provide load relief to Brockville TS B1R & M5 feeders which are currently loaded above planning guidelines.	10.5	2021-2022

Project ID	Project Name	Scope	Need Addressed	Cost - $M Net	Year(s)
LG-46	Manitoulin TS - Add Third 44 kV Feeder	Add new 44 kV breaker at Manitoulin TS, new feeder tie switches, and construct 1.5 km new 44 kV line to Little Current DS.	To maintain 44 kV feeder loading within protection limits during transformer or breaker outages.	4.6	2021-2022
LG-47	Point Au Baril DS F2 Extension	Extend the Point Au Baril DS F2 feeder for 8.5 km by double-circuit the existing F1 feeder north of Point Au Baril.	To provide load relief to the Point Au Baril DS F1 feeder which has substandard system protection and voltage.	3.6	2021-2022
LG-48	Aspdin DS F1 Feeder Upgrade	Upgrade 5 km of single-phase line to three-phase.	Address single phase line loading above planning guidelines.	1.3	2022

SS-03 Reliability Improvements

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	33.1
Primary Trigger:	System Efficiency		
Secondary Trigger:	Reliability		

Investment Need:

The Hydro One distribution system is normally planned based on a radial supply configuration. Due to system growth and development over time, there may be alternate feeds available to certain load centres or specific customer locations. However, alternate feeds may not be capable of supplying the entire load. Also, in many cases, only a single radial supply exists so there are no opportunities to transfer load during outages. Extended outages can be particularly disruptive to commercial and industrial customers due to lost business or lost productivity and in some cases lost/damaged product due to processing interruptions. Some industrial customers may also be sensitive to momentary supply interruptions due to lightning or even to voltage fluctuations which may occur when lightning strikes other parts of the system that do not directly supply them.

To improve reliability and increase customer satisfaction in certain areas, investments focused on improving backup capability, adding new tie-lines, and lightning mitigation may be needed.

Alternative 1: Status Quo

Address customer concerns about poor reliability in sensitive areas on a reactive basis only.

This alternative is rejected since it would lead to decreased customer satisfaction and continued poor reliability in areas where concerns have already been expressed. Not proceeding with this investment would leave customers susceptible to longer and more frequent outages that are characteristic of radially configured lines. The risk of serving customers at unacceptable power quality levels will also increase. If left unaddressed, poor power quality can lead to equipment damage and sustained outages for customers.

Alternative 2: Targeted Reliability Improvements (Recommended)

Implement targeted projects to improve reliability in areas where customer concerns have been raised and where practical system development opportunities exist to meaningfully improve system capability and performance.

Investment Description:

There are a variety of ways to improve system reliability. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Examples of projects to improve reliability include building tie lines to provide alternative supply capabilities, installing express feeders to critical load centers, improving sectionalizing capabilities on multi-branch feeders, adding voltage regulators or upgrading conductor to improve capability of existing ties, and installation of lightning arrestors on feeders. These reliability investments typically occur in areas with a high customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

<u>Constructing Alternative Supply Options & Improving Sectionalizing Capabilities</u>: To minimize the duration of an outage experienced, customers can be temporarily supplied by alternative sources as the faulted section of line is addressed. This is typically achieved by connecting two or more feeder sections through tie-lines and ensuring that appropriate equipment is in place to enable switching over to the alternative supply. Improved sectionalizing capabilities help reduce the number of customers impacted by sustained power interruptions.

<u>Reducing Line Exposure</u>: By decreasing the circuit length of a feeder, the total amount of conductor exposed to the elements is lessened. This reduces the likelihood of that circuit experiencing a fault due to natural elements, such as trees.

<u>Improving Power Quality through Line Upgrades</u>: Power quality can be improved by increasing conductor sizes or installing voltage regulating equipment.

<u>Installing Lightning Arrestors</u>: Lightning arrestors are used to prevent power interruptions due to lightning strikes. These are installed on feeders that experience a high frequency of lightning storms.

The proposed overall expenditure includes placeholder funding of approximately $3 million annually for planned reliability improvements to large distribution account customers based on customer engagement sessions.

A list of planned and scoped projects in excess of $1 million over the 2018-2022 period is provided below.

Project ID	Project Name	Scope	Need Addressed	Cost $M Net	Year(s)
RI-1	Nebo TS Feeder Extension to Binbrook	Construct a new 6 km 27.6 kV feeder and tie to Nebo TS M5.	Provide a loop feed for Binbrook area.	2.8	2019-2020
RI-2	Tilbury DS New Feeder	Add a new 27.6 kV feeder position at Tilbury West DS, construct 0.6 km 27.6kV feeder and transfer Tilbury West DS F2 load to the new feeder position	Provide a loop feed for Town of Tilbury and lighthouse cove area.	1.9	2019
RI-3	Puslinch DS 4th Feeder	Construct a new 27.6kV feeder for 2 km out of Puslinch DS.	Provide a dedicated supply to industrial customers for improved reliability.	2.9	2021
RI-4	Orangeville TS M3-M6 Tie Line	Construct approximately 10km of new 44kV line between Caledon DS and Sleswick DS (along Charleston Road).	Provide a loop feed for to enable backfeed during outages.	2.6	2022
RI-5	Tilsonburg-Norfolk Tie Line	Construct 4 km 27.6kV feeder tie between Tilsonburg TS M1 and Norfolk TS M1.	Provide backup supply for Town of Delhi loads.	1.1	2022

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction, as well as the usual risks around property rights for poles, anchors and tree trimming. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

Reliability Improvement projects will:

- Improve customer satisfaction levels, particularly where customer concerns have been raised;
- Reduce outage durations for specific load centers or customers; and
- May improve operational efficiency and safety through increased system flexibility on projects involving tie-line upgrades.

Outcome Summary:

Customer Focus	• Reduce outage durations/frequency for sensitive customer loads. • Reduce lengthy outages to certain areas by providing an alternate feed capability. • Mitigate voltage fluctuations due to lightning activity for industrial customers.
Operational Effectiveness	• Allow increased operational flexibility to supply some loads by an alternate means in order to perform planned and unplanned maintenance.
Public Policy Responsiveness	
Financial Performance	• Cost saving opportunities such as making provisions for future circuits or tie-lines during routine work such as road relocation, end-of-life pole replacements are pursued when possible. • Maximum benefit/cost outcome is a primary factor taken into consideration when selecting appropriate investments under this category.

Costs:

Cost estimates are based on historical actual costs. Costs are mainly affected by design requirements and conditions of construction. Costs are controlled by avoiding costly and complex design solutions where possible and by sub-contracting specialized civil work to external service providers.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	5.2	7.9	7.2	8.2	9.2	37.6
Less Removals	0.6	1.0	0.9	1.0	1.1	4.5
Gross Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**
Less Capital Contributions						
Net Investment Cost	**4.6**	**7.0**	**6.3**	**7.2**	**8.1**	**33.1**

**Includes Overhead at current rates plus Allowance for Funds During Construction*

SS-04 Demand Investments

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Program	**Plan Period Cost ($M):**	19.9
Primary Trigger:	Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

Minor distribution system modifications are required to address system needs identified by customer power quality complaints, feeder studies and system impact assessments. These system needs are identified by the Distribution System Code ("DSC") as "enhancements" (section 3.3) and are completed for the purposes of improving system operating characteristics or for relieving system capacity constraints. Responding to these needs ensures an adequate supply of electricity to customers.

Resolution of issues within the individual projects of this investment could include upgrading conductor size, voltage conversion, supplying three phase circuit where a single phase supply would not be adequate, or protection upgrades.

Alternatives:

This investment addresses issues that arise on a demand basis and typically relate to power quality, and feeder protection. As these issues arise on the distribution system, it is imperative for Hydro One to address them in an expedient and efficient manner. Completion is required to comply with the DSC.

Not proceeding with this investment would be a failure to comply with the DSC and result in critical issues remaining on the system, leading to deteriorated service reliability and power quality, decreased customer satisfaction and substandard supply. Damage to distribution system assets could also occur.

Investment Description:

The triggers of the projects within this investment are driven by customer requests to increase loading on the system or to resolve power quality issues. When a request is received, a system impact assessment is performed to investigate possible resolution. Technical criteria are used in assessing system and customer needs.

System enhancements addressed by this plan include items such as protection coordination, and installing new equipment or equipment upgrades.

This investment resolves lower cost, high priority issues identified by customers, feeder studies, or system impact assessments with a short lead-time. These investments generally cost between a few thousand dollars for low cost projects such as fuse upgrades upwards to a few hundred thousand dollars for costly upgrades such as voltage conversion or single to three phase line conversion.

Risk Mitigation:

To ensure customer satisfaction it is important that work is prioritized to avoid catastrophic failure of critical assets supporting large numbers of customers. Projects are prioritized among the work in the queue for a given work centre. Higher priority projects may need to be completed on a faster turnaround causing the lower priority projects to be delayed.

Result:

This investment will address the following:

- Maintain reliability and quality of service within supply standards; and
- Address customer issues in an expedient and efficient manner.

Outcome Summary:

Customer Focus	• Improve customer satisfaction by resolving high priority issues.
Operational Effectiveness	• Improve power quality by ensuring that protection settings are effective and within acceptable levels for customers.
Public Policy Responsiveness	• Adhere to DSC by maintaining reliability and power quality standards. • Address issues identified in feeder studies and/or system impact assessments.
Financial Performance	• Avoided costs by proactively replacing equipment that is causing issues on the system.

Costs:

As the types of issues that need to be resolved in this program are unforeseen, this work is considered non-discretionary and annual costs are based on historic spending.

The costs of the project are affected by the complexity of the work involved to resolve the reported issues. Costs are controlled by avoiding costly/complex design solutions where possible.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	4.1	4.3	4.4	5.0	5.0	22.6
Less Removals	0.5	0.5	0.5	0.7	0.7	2.7
Gross Investment Cost	**3.6**	**3.7**	**3.8**	**4.3**	**4.3**	**19.9**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**3.6**	**3.7**	**3.8**	**4.3**	**4.4**	**19.9**

**Includes Overhead at Current Rates.*

SS-05 Distribution System Modifications

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	40.1
Primary Trigger:	Mandated Service Obligation		
Secondary Trigger:	Reliability		

Investment Need:

These investments provide adequate supply to accommodate system load growth on the distribution system with new or modified distribution facilities.

These investments focus on correcting feeder load balance, voltage quality and protection coordination, which are issues that arise over time due to variability in feeder load resulting from changes like natural load growth and economic changes. As these changes occur, the distribution of load along feeders can vary significantly. This can affect the voltage quality and conductor loading, cause improper protection operations, and potentially cause equipment ratings to be exceeded.

To identify issues that have arisen, the distribution system is reviewed for load balance and protection coordination on a cyclical basis. To correct issues that arise such as feeder load balance, voltage quality and protection coordination issues, the scope of work involved can include rebalancing and re-phasing feeders, changes to feeder configuration, new or modified protection equipment and voltage regulators, feeder expansions, and construction of new feeders and voltage conversion.

Alternative 1: Do Nothing

Not proceeding with this investment increases reliability and safety risks associated with low feeder end voltages, overloaded equipment, and improper protection operation. It also increases the risk of not adhering to industry standards for voltage regulation and current levels.

Alternative 2: Make Frequent Investments

This alternative would correct feeder load balance and protection coordination issues on a frequent basis driven by any system changes.

Annual investments on each feeder are not recommended because year over year the changes to load distribution are relatively minimal and this alternative does not lead to the most efficient use of resources.

Alternative 3: Infrequent Investments

This alternative would correct feeder load balance and protection coordination based on a cycle greater than six years.

A review cycle longer than six years is not recommended because the investment needs resulting from natural load growth and economic changes would not be addressed in a timely manner. This could cause issues in terms of coordination of the cycle study reviews with the current line patrol frequency. This would significantly increase the risk of operating the distribution system with overloaded equipment, voltage issues and improper protection.

Alternative 4: Planned Six-year Cycle (Recommended)

This alternative would correct feeder load balance and protection coordination based on a six-year review cycle, consistent with the outcomes of the studies described in Section 2.3 of the DSP. The recommended six-year review cycle length aligns with Hydro One's six-year inspection cycle mandated by the Distribution System Code, Appendix C. Acting on information about a feeder that has just been inspected reduces risks arising from data errors or discrepancies.

This represents a balance between addressing natural load growth in a timely manner and effectively applying resources to maintain all distribution feeders at appropriate voltage and protection levels.

Investment Description:

The work performed under this investment is coordinated with feeder studies that will be conducted on a six-year cycle through Development OM&A activities. The investments address the needs identified through the studies and are executed through this program on a priority basis.

Separate scopes of work are developed for each distribution station and their downstream feeders based on the results of feeder studies. Work is prioritized based on the severity and criticality of the issues being addressed.

The investment is expected to complete approximately seventy-five projects annually over the five-year business plan.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction. These risks will be mitigated by ensuring that appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Implementation timing is dependent on resources available in the work centres where the projects are occurring.

Result:

This investment provides the following results:

- Reliability and safety risks associated with improper protection coordination, overloaded equipment, and non-standard voltage levels are reduced;
- Power quality issues are reduced;
- System voltage and current levels will be maintained within industry standards; and
- Improve operational efficiency with effective protection schemes.

Outcome Summary:

Customer Focus	• Minimize power interruptions to customers by improving voltage levels and power quality with adjusted protection settings.
Operational Effectiveness	• Improve operational efficiency by addressing overloading on parts of the system, proper phase balancing and ensuring effective protection schemes to deal with changes on the system.
Public Policy Responsiveness	• Maintain system voltage and current levels within industry standards.
Financial Performance	

Witness: Lyla Garzouzi

Costs:

As the types of issues that need to be resolved in this program are unforeseen, this work is considered non-discretionary and annual costs are based on historic spending. Final costs of the program are affected by the scope and complexity of the modifications required for each project. Projects that could incur significant costs get released for design and estimate before execution. This gives system planners an opportunity to consider alternatives to the proposed work and include longer term plans where possible. Other projects which are low in cost or have no alternatives available go straight to release for construction.

Controllable costs are minimized by selecting the most cost effective alternative that addresses the issues.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	8.3	8.2	9.1	10.0	10.0	45.5
Less Removals	1.0	1.0	1.1	1.2	1.2	5.5
Gross Investment Cost	**7.3**	**7.2**	**8.0**	**8.8**	**8.8**	**40.1**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**7.3**	**7.2**	**8.0**	**8.8**	**8.8**	**40.1**

**Includes Overhead at current rates.*

SS-06 Worst Performing Feeders

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	49.9
Primary Trigger:	Reliability		
Secondary Trigger:	Customer Service		

Investment Need:

Hydro One has various programs that deal with asset based sustainment. Most sustainment programs rely on various condition-based and/or time-based data and use various characteristics such as asset condition, demographics, criticality, utilization and others to determine which feeders are most likely to lead to a failure incident over the planning period. Provisions are made to service those assets with immediate maintenance requirements.

Recently, Hydro One has been able to leverage the available reliability data and has come up with a list of the "worst performing feeders" on the system. Rather than using pure asset-based requirements, the identification of these feeders is primarily based on their reliability metrics as a contributor to System Average Interruption Duration Index ("SAIDI") and/or System Average Interruption Frequency Index ("SAIFI"). These metrics are referred to in combination as Customer Average Interruption Delivery Index ("CAIDI"). [$SAIDI \div SAIFI = CAIDI$]. The trending of performance also factors into the determination of the list.

The worst performing feeders program will include those feeders whose contribution to SAIFI/CAIDI is three times the average feeder's contribution. Based on preliminary analysis, this represents approximately 230 feeders whose contribution to SAIFI is three times the average and approximately seventy feeders whose contribution to CAIDI is three times the average. Improving performance of this small number of feeders should improve reliability of the overall system for customers.

Generally, the primary reason for a feeder being on the worst performing list is related to vegetation management. However, solving the issue is not necessarily about more aggressive forestry practices. Modernization can be a significant contributor to improvement as can placement of the line away from pending forestry contacts. Moreover, improved communication would help to address outages more quickly and reduce their duration to the benefit of customers on these lines.

Alternative 1: Status Quo:

This alternative continues to use the current practice of analyzing and addressing feeder components based solely on their individual characteristics. This alternative misses the opportunity of providing targeted reliability improvements to customers.

Alternative 2: Initiate Program to Modernize Worst Performing Feeders (Recommended)

This alternative specifically targets those feeders whose contribution to SAIFI/CAIDI is three times the average feeder's contribution.

The program will invest in communication to open point switches, installed sectionalizers, and feeder breakers. These investments will allow the grid control room to more quickly identify the origin of a fault and perform operational actions in order to improve reliability. Also, this program will address those feeders where an asset-based approach or vegetation management programs cannot eliminate high numbers of momentary outages.

Initial estimates suggest that this program itself could, over time, increase the reliability of the distribution network by approximately one percent.

Investment Description:

This program focuses on overall feeder performance using reliability data. This approach allows Hydro One to upgrade entire feeder sections rather than just underlying components on an individual basis. Recently improved components on these feeders would not be replaced.

This investment program will use feeders' contribution levels to metrics to identify those feeders where proactive action will result in tangible benefits. Analysis of historical SAIFI contribution values will identify those feeders that are experiencing a significant number of interruptions. Analysis of historical CAIDI contribution values will identify feeders where outage duration is the longest.

This investment program will focus on reducing of two key elements of reliability:

1. Reducing the number of system interruptions (SAIFI) – Key causes of interruptions that can be proactively addressed are vegetation encroachment and equipment failure. Off-road to on-road feeder relocations and remote conditions monitoring are all options for reducing momentary outages.
2. Reducing the duration of customer interruptions when they occur (CAIDI) – Use of fault detectors, automation and remote control of switching equipment and "self-healing-grid" solutions are all options for reducing outage duration.

The program will take proactive action to increase the reliability of the distribution network using a number of solutions:

- Equipment monitoring and alerts;
- Adding monitoring and remote control to existing equipment capable of supporting SCADA, which will be done for problematic feeders to support rapid response to outages when they occur;
- Deployment of modern switching equipment that can act autonomously and can also be remotely controlled to provide isolation and sectionalizing (which is particularly important around existing manually operated open points) with integration to the Distribution Management System ("DMS") through high speed wireless communication systems;
- Construction of additional ties between feeders capable of supporting load transfers; and
- Relocating sections of feeders from off-road to on-road.

Risk Mitigation:

Risk associated with completion of the program is minimal and in line with other upgrade programs. Availability of resources and length of outages are the biggest factors to manage.

The level of approved program investment would impact on modernization effort and hence improved reliability.

Result:

This investment will have an impact on the following:

- Reducing the customer hours of outage by an automated system of back-to-back supply for the faulty feeder and improving reliability through SAIFI and CAIDI metrics resulting in increased customer satisfaction;
- Reducing Hydro One outage times by 50% on faults involving main feeder trunks through identifying the location of faults through DMS monitoring and control telemetry system instead of dispatching a crews to drive along feeders to perform the same task; and
- Performance improvement by allowing the grid control room to quickly identify the origin of a fault and perform operational actions to allow back-to-back supply for the faulty feeder.

Outcome Summary:

Customer Focus	• Improved customer reliability through back to back supply from alternative adjacent feeders. • Improved response times to dispatch.
Operational Effectiveness	• Improved efficiency through enablement of back-to-back switching and remote automation through DMS. • Reduced public safety risk by quickly and accurately identifying dangerous faults. • Improved reliability where current programs are not as effective in removing momentary outages.
Public Policy Responsiveness	• Improved compliance with DSC requirements in responding to trouble situations.
Financial Performance	• Reduced unit costs through more accurate and timely location of faults as well as potentially fewer and more targeted truck rolls. • Reduced level of field effort and, therefore cost, dealing with trouble events.

Costs:

Cost estimates are planners' estimates. Individual feeders may have different issues and hence different solutions. Individual estimates will be obtained in order to fully define the volume of work required.

The factors which affect the estimates for this investment are determined by the annual purchase of the smart equipment units. Controllable costs for this program were based on modernization of open points.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	7.1	10.1	10.5	10.9	11.3	49.9
Operations, Maintenance & Administration and Removals	-	-	-	-	-	-
Gross Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**7.1**	**10.1**	**10.5**	**10.9**	**11.3**	**49.9**

**Includes Overhead at current rates.*

SS-07 Advanced Distribution System ("ADS")

Start Date:	Q1 2013	**Priority:**	High
In-Service Date:	Q2 2018	**Plan Period Cost ($M):**	5.0
Primary Trigger:	System Operational Objectives		

Investment Need:

The ADS investments were part of the smart grid investments outlined in Exhibit D1, Tab 3, Schedule 5 (Customer Services Capital) of EB-2013-0416. They were originally planned for completion within the last approved rate period. Investments were delayed due to a later than anticipated release of a version of software that incorporated more functions into one platform.

The current Distribution Management System ("DMS") went in service in 2012. A lifecycle system refresh is planned to replace hardware and software system components. Specifically, two key sub-projects were delayed: (1) the "DMS Upgrade" project; and (2) the Demand Response for Operations project. The DMS Upgrade project will provide the functionality of the following projects identified on pages 5 to 7 of Exhibit D1, Tab 3, Schedule 5 in Hydro One's last distribution application (EB-2013-0416): DMS Enhancements, Selective Load Shedding, Infrastructure Support, Mobility Solutions and Online Operating Diagrams projects.

The DMS is a control system that monitors and controls the distribution system. It provides a platform for distribution supervisory, control and data acquisition (SCADA). It also provides a set of advanced applications that enable proactive management of the distribution system (such as fault location). The new DMS will include new functionality that will improve operations by enabling field crews with a mobile DMS that they can use to have real-time situational awareness of the distribution system.

The DMS Upgrade project was delayed due to a later than anticipated release of a version of the relevant DMS software that accommodates distributed energy resource management and integrates the broad set of distribution modernization functions (such as mobility solutions). This software version was originally thought to be released in mid-2014, but is now scheduled to be released in 2017.

The Demand Response for Operations project will pilot a system that optimizes electric load and supply on a local basis leveraging all of the variable load (electric vehicle, energy storage, residential/commercial demand response) and generation (dispatchable renewable, energy storage) available. The Demand Response for Operations project was delayed to find more cost effective energy storage solutions.

Alternatives:

Not proceeding with the DMS Upgrade project will see the system go out of support. It will also delay the operational benefits associated with the new version of the software which include management of distributed energy resources. Failing to proceed with this investment would result in an increased risk of application failure which would impact Hydro One ability to manage its deployed smart grid assets.

Not proceeding with the Demand Response for Operations project will impact Hydro One's ability to manage the increasing volumes of customer-owned generation and microgrids expected to proliferate in the coming years.

Investment Description:

Planned investments for the DMS Upgrade project include hardware refresh, server operating system upgrade, DMS software upgrade as well as rollout of the DMS to be available for field crews.

Planned investments for the Demand Response for Operations project will see Hydro One install assets that monitor and control customer-side generation and storage assets and integrate them with control systems at the substation and the control centre.

Risk Mitigation:

DMS Upgrade Project

- As with all complex control system upgrade projects, the project entails system integration and technology risks. Hydro One has assigned an experienced team that worked on the original DMS implementation.
- As the DMS is being deployed to field crews for the first time, there are change management risks associated with training and adoption. A comprehensive change management program is planned to mitigate these risks.

Demand Response for Operations Project

- As the project will be piloting the integration of several new technologies (energy storage, solar, home energy management systems, etc.), there are system integration and technology risks. Hydro One will bring in external resources who have implemented similar systems elsewhere to mitigate these risks.

- As the project will be piloting technology on both the customer-side and grid-side of the meter, there are risks with the technology failing or customer expectations not being met. A comprehensive customer communication strategy will be developed that ensures clear communication with customers to set realistic expectations. Technology will be selected, engineered and commissioned to ensure they are reliable and safe.

Result:

DMS Upgrade Project

- Provide further integration of smart grid capabilities into the central control system for operators.
- Equip field crews with new mobile systems they can use to restore power more quickly and execute planned outages more efficiently.
- Enables more surgical load shedding during bulk electric system emergencies that would maintain distributed generation and critical loads (hospitals, water treatment plants, etc).

Demand Response for Operations Project

- Defer local distribution investment by maintain load below a set point by leveraging generation and storage assets.
- Increases the load capacity factor of the distribution system and reduces the variability of load and generation.
- Establish the systems and processes to manage the proliferation of customer-side generation and energy storage systems.

Outcome Summary:

Customer Focus	• Enable customer-side generation and storage assets for the benefit of both customers and the grid.
Operational Effectiveness	• Enhanced reliability of distribution system by providing field crews additional situational awareness on the real-time state of the distribution system and location of faults. • Increase operational efficiencies related to how the distribution system is studied in the planning time frame and provide more tools for the control room and field crews in real-time operations. • Improve the efficiency of distribution cycles studies by leveraging the accurate network topology and the state estimation function. • Improve efficiency of storm management by providing an electronic mimic of the distribution system in the operating centres that can replace the paper pinning.
Public Policy Responsiveness	• Comply with the public policy objectives set out in the OEB *Supplemental Report on Smart Grid* (2013) including: ○ improving customer control; ○ enabling power system flexibility; and ○ building adaptive infrastructure.
Financial Performance	

Costs:

DMS Upgrade Project Costs associated with the DMS Upgrade project are primarily driven by:

- Required testing effort;
- Hardware and software costs; and
- Integrations.

These costs have been minimized through:

- Requiring that all customizations be reviewed for priority and approved by the Steering Committee for their approval before proceeding;
- Utilizing a mixed team of contract and internal resources to perform testing of the system;
- Going to competitive bid for all hardware and software components of the upgraded DMS;
- Minimizing the number of integrations and using resources experienced with the existing integrations to design, build and test the new integrations; and
- Demand Response for Operations Project.

Costs associated with the Demand Response for Operations Project are primarily driven by:

- Cost of solar photovoltaic systems;
- Cost of energy storage systems;
- Cost of onsite installation services; and
- Integrations with utility systems (substation protections and the DMS).

These costs have been minimized through:

- Delaying the project start to find more cost effective solar and energy storage systems as they become more commercially viable;
- Leverage experience in performing onsite installations for conservation programs to minimize install cost; and
- Leverage the resources of the inflight DMS project to perform the integrations required to monitor and control.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	5.0	-	-	-	-	5.0	
Less Removals	**-**	**-**	**-**	**-**	**-**	0.0	
Gross Investment Cost	**5.0**	-	-	-	-	**5.0**	**61.2**
Less Capital Contributions	**-**	**-**	**-**	**-**	**-**	0.0	
Net Investment Cost	**5.0**	-	-	-	-	**5.0**	**61.1**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-01 Transport & Work Equipment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	201.0
Primary Trigger:	F1-Asset renewal / maintenance		
Secondary Trigger:	Capital Program		

Investment Need:

Hydro One controls and manages approximately 8,000 Fleet vehicles which support the various lines of business, including Provincial Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations. These include, but are not limited to CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. This results in minimized environmental impacts and optimized line-of-business productivity by minimizing downtime, travel time, and by optimizing technology and continuous improvement opportunities.

Transport and Work Equipment ("TWE" or "Fleet") expenditures for 2018 through 2022 are primarily required to accomplish the following:

- Replace end of life core TWE;
- Support the growing levels of transmission and distribution capital and OM&A sustainment, development and operations work programs;
- Support the Forestry Mechanical Brushing Program, and Provincial Lines Pole Replacement Program; and
- Replace aging helicopters with newer safer and more capable aircraft.

Alternatives:

TWE plays a wide reaching and integral role in the day-to-day operations, safety and success at Hydro One. Availability of TWE has a direct impact on work programs and this proposal is to maintain the Fleet compliment.

The primary alternative to the proposed plan centres on a reduction in capital spending on TWE in favour of increased use of rental equipment, if the required equipment is available, and extended retention of existing equipment to satisfy work program and staffing requirements. Hydro One employs specialized equipment specifically outfitted to Hydro One safety specifications. Short term rentals are utilized where applicable on light duty vehicles but history has shown that due to the nature of the work, any rental savings is quickly offset by additional costs incurred by the normal wear and tear on the rental vehicles in this type of industry. The result is increased maintenance costs on the retained vehicles, increased vehicle downtime and decreased equipment availability.

Investment Description:

Fleet capital replacement requirements are based on:

1. Industry standards (manufacturer's recommendations) for life cycle expectancy;
2. Net Book Value (NBV) to Original Capital Value (OCV) ratios; and
3. Operating cost drivers which are then linked to the Business Plan and Work Programs.

Currently, the fleet is at 39% NBV to OCV where industry standards, established through a combination of Canadian Utility Fleet Manager workshops, direction from Fleet Management Companies and Industry experts, suggest that 45% as an optimum level. Our present replacement criteria are based on manufacturers' recommendations and repair history.

Key contributors to the 2018-2022 capital program include:

- The replacement of core transport and work equipment (about 8%, approximately 650 vehicles, of Fleet annually);
- Incremental vehicle and equipment requirements to support the increase in the Mechanical Brushing Program and the Provincial Lines Pole Replacement Program; and
- Replacement of aging helicopters.

Table 1 – Forecast of Acquisitions for 2018 to 2022

Equipment Type	2018		2019		2020		2021		2022	
	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units	Cost ($M)	# of Units
Light[1]	7.3	322	8.4	369	7.9	348	8.3	365	7.4	323
Heavy[2]	14.0	108	15.8	121	16.9	129	17.8	136	21.0	159
Off-Road[3]	6.3	26	7.1	29	7.3	30	7.6	31	8.0	33
Miscellaneous[4]	4.0	173	4.6	197	4.6	201	4.6	198	3.9	166
Helicopter	2.4	0.5	2.4	0.5	2.4	0.5	2.4	0.5	2.4	0.5
Incremental Additions [5]	1.1	9	1.3	12	1.3	12	1.3	12	1.4	12
Total	**35.0**	**639**	**39.5**	**729**	**40.4**	**720**	**42.0**	**743**	**44.1**	**694**

Note: Number of units is based on average unit costs per category of equipment and is subject to change based on specific LOB staff and work program requirements.
Numbers of units are based on the Tx and Dx Capital Investment Costs

[1]Light – cars, SUVs, pickups, vans
[2]Heavy – service trucks, highway tractors, radial boom derricks (RDB), bucket trucks
[3]Off Roads – rubber tire, tracked equipment
[4]Miscellaneous – boats, chippers, tensioners, manlifts, forklifts
[5]Incremental Additions – Tracked and Rubber Tired Grinding/Mulching units, Tag-a-long Chippers, Bulldozers are used for the Forestry Mechanical Brushing Program and RDB for the Provincial Lines Pole Replacement Program.

Risk Mitigation:

Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers.

Light vehicles are replaced after six years or 180,000 km. Heavy vehicles have several replacement guidelines depending on the type of equipment; service trucks are replaced after six years or 300,000 km, and work equipment-single axle is replaced after eight to ten years or 400,000 km. Work equipment-tandem axle is replaced after twelve to fourteen years or 400,000 km. Off-Road and Miscellaneous equipment is replaced on a case by case basis depending on utilization and condition of the equipment and ongoing need.

Helicopters are replaced on a case by case basis depending on utilization, condition of the aircraft and the cost of refurbishment. This asset strategy is designed to address the following risks:

- Equipment failure - Retaining and operating older equipment increases the probability of failure, which creates costly downtime for crews and increases safety risk for employees and the public;
- Scheduled Outages - Customers (especially large industrial) are impacted when equipment is unavailable because the outage must be rescheduled;
- Emergency response - Unplanned work (i.e., storm response, trouble calls) requires timely dispatch and lack of available equipment will impact customers by exacerbating outages;
- Work Schedules - Delay in work programs impact the Line of Business (LOB) project costs and decrease operational effectiveness;
- Increasing costs - Repair time and maintenance costs are reduced since aging equipment requires more maintenance as seen in table 2; and
- Environmental goals - Environmental Impact to the public is affected by operating aging equipment as newer, maintained vehicles tend to have a lower carbon footprint.

Result:

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process and to plan for future TWE requirements based on work program and staffing forecasts. The TWE Replacement Program annually analyzes its five-year business planning cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital replacement program, on an annual basis, is evaluated against the business plan and is subject to the LOB's work program prioritization and forecasting process.

The objective is to maintain a stable fleet replacement program and minimize capital investment fluctuations year-over-year. A reduction in capital spent in a given year will result in increased operating costs, which could ultimately result in increased equipment rates.

This investment will:

- Ensure compliance with all safety standards, as well as Ministry of Transportation (MTO) and regulatory requirements;
- Allow Hydro One to maintain and improve its present core fleet level of 39% versus the industry standard of 45% NBV. At the end of 2022 it is forecasted to be 41%.

Fleet Services will leverage the telematics data to institute the baseline metrics with respect to equipment utilization and productivity;
- Maximize, productivity efficiencies and utilization; and
- Optimize repair time and fleet size.

Outcome Summary:

Customer Focus	• Optimize Fleet Service levels to mitigate potential delays in response time to unplanned incidents, such as trouble calls and storm response.
Operational Effectiveness	• Fleet vehicles and other specialized equipment at optimal levels of availability reduce human effort and minimize risk of personal injury. • Optimal investment levels allow employees to have the right equipment to do their job, increase employee engagement levels, minimize risk of injury and increase work satisfaction.
Public Policy Responsiveness	• Optimal investment levels allow for maximum equipment efficiencies and minimize Hydro One's carbon footprint. • Ensure compliance with all codes, standards and regulations to maximize shareholder value and sustainably manage our environmental footprint. • Vehicles will be maintained at an optimum level to ensure public and employee safety and to meet Ministry regulations.
Financial Performance	• Ensure savings from operational effectiveness are sustainable. Control maintenance costs (external repair, parts and internal labour), potential rental costs and maintain equipment rates at optimal levels to ensure OEB mandated ROE is achieved.

Costs:

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	35.0	39.5	40.4	42.0	44.1	201.0
Less Removals	-	-	-	-	-	-
Gross Investment Cost	35.0	39.5	40.4	42.0	44.1	201.0
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	35.0	39.5	40.4	42.0	44.1	201.0

**Includes Overhead at current rates.*

GP-02 Real Estate Field Facilities Capital

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	185.9
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Non-System Physical Plant		

Investment Need:

The Field Facilities Capital work program addresses the accommodation portfolio of administrative and service facilities in terms of improvements, building additions and new facilities as determined by Hydro One's operational requirements and asset condition. This program ensures that essential and supportive improvements are made to administration and service facilities to minimize building and site related risks to the operations; serve operational requirements; and promote efficiencies in the maintenance and operation of the facilities in the longer term.

Capital investment is periodically required in order to continue to provide appropriate and adequate accommodations for core work programs and changing requirements of the various lines of business. The investment need is driven by the following key factors:

- deteriorating facilities that are at or near the end of life;
- compliance with current regulatory requirements, such as Accessibility for Ontarians with Disabilities Act and the Ontario Building Code;
- expanding work programs;
- new accommodation needs;
- evolving work practices;
- improved health and safety;
- improved security;
- sustainable development; and
- work efficiency and productivity.

More than 40% of administration and service facilities are estimated to be more than 40 years old. These facilities are largely undersized, ill configured and underperforming to current operational requirements with resulting increase to operating costs for maintenance and repair and inefficiency to facility and business operations.

The Field Facilities Capital work program focuses on undertaking facility work encompassing improvements, additions or new facilities. Work is undertaken on a priority and timely basis at a level of expenditure required to support the business operations to fully deliver the prescribed various work programs addressing network requirements, customer needs, corporate and government policy and regulatory/licensing directives in a safe, efficient and cost effective manner. This work is conducted on a project basis.

Alternative 1: Status Quo

This alternative is to effectively curtail future investment on a minimal basis in an attempt to operate within the outdated facilities.

This alternative is not sustainable. Without necessary capital repairs, upgrades and replacements, facility conditions will deteriorate to the point where efficiency and safety become impaired. Incidents arising from this alternative will hamper Hydro One's ability to perform its work and serve customers.

This alternative would require additional operating expense for maintenance repairs, which have not been factored into this Application. The risk created by this alternative, and the additional operating maintenance expense it would create, caused it to be rejected without further analysis.

Alternative 2: Update Facilities *(Recommended)*

This alternative would bring field facilities to an acceptable state of repair and make strategic additions or replacements where beneficial.

The spending requested herein is an estimate of the work to be performed over the planning period. The development of field facilities entails an on-going, comparative evaluation of alternatives, which entails the expansion and/or renovation of existing facilities, the lease or purchase of suitable facilities and greenfield developments against maintenance of the status quo condition. The ultimate investment will be dictated by the circumstances in place. The objective is to pursue the most cost effective strategy that addresses operational requirements and manages risk. Operational considerations are for both existing and future requirements; the latter considers changes to the business, e.g., volumes and delivery strategy. Regardless, each substantial investment will be subject to analysis and approval based on its benefit prior to implementation.

The prime consideration throughout is to extract the value of existing facilities through ongoing operations, maintenance and sustainment investments in line with operational requirements. Where facility and/or operational conditions/requirements dictate an examination of facility alternatives, the objective is to derive the greatest net assessable benefit to the company.

Investment Description:
The key program work activities include:

- replacement of major building system/components, including roof structures; windows and cladding; heating, ventilating and air conditioning (HVAC) systems; electrical, lighting and control systems; and other crucial/fundamental structural elements and building systems that are at end of life;
- site replacements and additions, including drainage; asphalt, fencing; and septic/well (servicing); and
- addition and/or renovation of existing facilities and the acquisition or development of new facilities to address existing and/or new accommodation requirements.

The required capital investment for field facilities is outlined in the Costs section below. These amounts are needed to fund required improvements of existing facilities and the development of new accommodation solutions through renovation and/or expansion and the acquisition or development of new facilities as required by the company's work programs. Projects can be multi-year; and the work is contingent in several projects on the successful identification and acquisition of development sites and in all instances obtaining the requisite municipal planning approvals. Furthermore, certain projects are tied to the successful and timely completion of utility acquisitions or others may be adjusted for emerging acquisition opportunities.

The current estimate of the volume of work to be completed annually at individual sites/facilities is as follows:

Work	Annual Completed Projects
New Facilities and Major Renovations	2 – 4
Site Improvements (asphalt; drainage; servicing; fencing; security)	20 – 25
Building Envelope (roof; windows/doors; cladding)	20 – 30
Mechanical & Electrical (HVAC; lighting; generators)	15 – 20
Minor Building Renovations and Additions	10 – 15

Benefit is realized through a number of factors, such as lower cost, improved operational performance, regulatory compliance, enhanced health & safety, reduced risk, enriched life cycle management and adaptability to address known or anticipated change.

Risk Mitigation:

Cost certainty for new operating centres is established through the use of a scalable template design and experience from recently completed projects. Developments are completed in accordance to prevailing commercial standards and practices.

Developments of new facilities are in various instances dependent on the availability of suitable sites and requisite municipal approvals, which is managed through advance planning and acquisition. Development interests are cultivated by leveraging municipal officials/departments and utilizing the services of the real estate and development community.

Facilities redundancy and low value investments are managed by conducting regular reviews with the various lines of business to understand and align with current and emerging work programs and identify common requirements and workplace synergies. Furthermore, planning is integrated with utility acquisition strategies and objectives to identify opportunities, create flexibility and manage facilities investments.

Result:

- Field Facilities that serve current operating requirements of the various lines of business.
- Field Facilities commitments and investments aligned with known and emerging operating requirements and corporate business decisions.
- Maintenance of existing Field Facilities through timely replacement of major building systems/components.
- Enhanced health & safety of employees operating within Field Facilities.

Outcome Summary:

Customer Focus	• Improve the ability of the lines of business to address customer needs through facilities that commensurately align with operational requirements.
Operational Effectiveness	• Maintain and improve operational effectiveness of the lines of business through timely and strategic facilities investments.
Public Policy Responsiveness	• Comply with government policy and regulatory/licensing directives.
Financial Performance	• Cost savings realized through the broad consideration of facilities alternatives. • Cost effectiveness realized through regular assessment and timely investment. • Cost efficiency realized through facilities investments that align with current and emergent operating requirements and business decisions.

Costs:

The development of facilities and resulting final cost of a project are influenced by various factors beyond the typical realm of design, such as market, regulatory and site conditions/factors. Regulatory and site conditions are somewhat predictable through assessment, but not overly influenced by design considerations. Whereas, the market is highly influential to final cost for availability of suitable sites, market opportunity and interest and competing demand. These market factors could have a significant negative or positive influence to the cost of the project. Furthermore, existing facility conditions, site and/or building, may have significant latent defects that, irrespective of early assessments, are undetectable until implementation and could contribute to significantly higher costs.

The cost for the development and/or renovation of facilities is controlled where applicable through template design, consistency of application, and the adoption of commercial building standards and practices.

Witness: Rob Berardi

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	35.4	42.9	36.9	36.9	33.9	185.9
Less Removals						
Gross Investment Cost	35.4	42.9	36.9	36.9	33.9	185.9
Less Capital Contributions						
Net Investment Cost	35.4	42.9	36.9	36.9	33.9	185.9

**Includes Overhead at current rates.*

GP-03 MFA Servers and Storage

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	16.0
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. Hydro One's Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping the business running effectively. This investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time.

Key systems and the data generated must always be available (99.5%) to customers and employees involved with the delivery of customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities. As more customers are integrated into the SAP landscape and generate more business analytics the need for SAP capability increases. Move-to-Mobile and Customer High Bill Alerts are projects that require new hardware. Merger and Acquisition activity is another component that drives an increase to our server landscape.

Enterprise applications being refreshed (to stay within vendor supported levels) drive refresh of the overall environment. Hardware refresh is also required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Without refreshed assets, Hydro One would have difficulty enforcing performance agreements with vendors and could potentially be exposed to large, un-warranted costs. Conversely, refreshing as per vendor requirements allows for sustainment costs due to technology improvements being implemented as part of new deployments to be favourably re-negotiated.

HONI continues to increase its virtualization footprint for any new/existing applications that are refreshed. With virtualization, several operating systems can be run in parallel on a single server. This parallelism and allows Hydro One to better manage updates and changes to the operating system and applications without disrupting the user. Virtualization can improve the efficiency and availability of resources and applications in an organization.

Hydro One continues to explore opportunities to leverage cloud based application/infrastructure services while complying with HONI's corporate data security policies around NERC, CCAI, and PIPEDA.

IT system availability directly impacts the productivity of employees who use the technology. IT availability also has direct impacts on the availability and security of the power network itself given the modern suite of tools that are relied upon to monitor and operate the grid.

Alternative 1: Delay Refresh

This alternative would seek to delay the replacement of equipment past its current life-cycle expectancy.

Not refreshing end-of-life servers or delaying investment in storage devices beyond the current level will impact the reliability of IT systems and increase the incidents of failure. This reduced reliability will impact application uptime and overall system availability for customers and internal users alike. It will also drive additional sustainment costs, as many vendors commonly charge their services at a premium rate to support end of life products. It will remove the ability to build out capacity on-demand capability and will cause hardware to be added frequently and incrementally. This "just-in-time" server add strategy comes at a significant premium due to the lack of bulk buys, multiple complex setup and staging processes and potentially costly delays to important Business IT projects if hardware procurement has any issues.

Alternative 2: Refresh In-line with Life Cycle Guidelines (Recommended)

This alternative would keep assets current and refreshed. This option will support the maintenance of up-time requirements and ensure that data and processing ability is available to customer and employees.

Investment Description:

Wintel servers are refreshed on a three- to five-year cycle and UNIX servers are refreshed on a five- to seven-year cycle. These cycles fall within industry best practices and maintain warranties within an acceptable level. Virtualization technology is being leveraged to further increase the life of our physical servers. The replacement cycle for refresh of Wintel and Unix servers is to maintain vendor-supported levels and includes hardware upgrades, capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing.

In determining when systems require replacement, the functionality, operating and maintenance (i.e., standard warranty or extended warranty) costs are assessed. The funding for the servers and storage refresh/replacement program varies year over year depending on hardware lifecycles and business requirements for increased processing capacity.

Costs in 2018 to 2022 reflect typical lifecycle refresh of end of life storage hardware.

Risk Mitigation:

Replacement of infrastructure as proposed in this investment is a fairly routine occurrence that has been performed many times within the Hydro One environment by the staff that will be involved in this project. While issues occur, the risk of project failure is very low and most adverse situations can be anticipated and addressed from experience.

Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome. In the event of hardware failure, defects discovered, or resource constraints the project will work the systems integrator equipment manufactures to resolve issues or modify scope timelines until the issue can be resolved or architected.

Result:

A proactive investment approach reduces the risk of prolonged IT system outages and reduces the costs of unplanned investment for problem resolution. It also reduces the risk to

Hydro One's ability to respond to business requirements and project delivery due to IT system integration and scalability impacts.

Outcome Summary:

Customer Focus	• Support information availability to customers ensuring that systems are supported and reliable. • Improve customer satisfaction around ease of use and experience of our customers when accessing billing information on e-customer.
Operational Effectiveness	• Increase productivity by ensuring that applications / systems function as designed and provide Hydro One employees with the information they require to perform their daily work effectively.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost by minimizing the potential for costly outages and unplanned refreshes or upgrades. • Maintain vendor support and the ability to enforce performance or availability SLA's thus avoiding increased costs.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs. The market for these products has matured significantly over the last decade. Major cost fluctuations are not anticipated and, in any event, are foreseeable and addressable through sound procurement strategy.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.2	3.2	3.2	3.2	3.2	16.0
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	3.2	3.2	3.2	3.2	3.2	16.0
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.2**	**3.2**	**3.2**	**3.2**	**3.2**	**16.0**

**Includes Overhead at current rates.*

Witness: Lincoln Frost-Hunt

GP-04 Minor Fixed Assets - Desktop, Laptop, Printer

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	9.8
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System (GIS). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for field staff upgrading and maintaining the power system. Minor Fixed Assets ("MFA") are the method by which the information and capability of these enterprise systems are provided to employees. Currency and functionality of the MFA fleet is critical to allowing employees perform their work productively.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of customer service programs and Distribution work management programs linked to H1 Customer satisfaction goals/KPIs – Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

MFA equipment includes:

- Desktops, Laptops, and Printers used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications;
- Tablets used with, among other things, Geospatial Information Systems ("GIS") applications for undertaking system design work and for asset condition assessments;
- Rugged Tablets and mobile devices used by field staff for entry of work related data; and
- Plotters commonly used by Hydro One engineering and operations staff for design work and to plot system maps.

Replacement of MFA that have reached the end of their useful life is necessary to address warranty considerations and to maintain hardware reliability, as well as to upgrade existing equipment to meet business performance needs.

Equipment refresh maintains or reduces maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty.

Alternative 1: Delay Hardware Refresh

This alternative would delay the refresh of assets and address increased failure and performance of the obsolete assets.

A delay in hardware refresh would affect operational effectiveness and our ability to serve customers. Aging hardware impacts application performance which in turn impacts ability to provide timely responses to customers in a call centre environment. In other areas of the business aging PC's perform poorly as new state of the art applications are deployed demanding more processing power and memory.

Delaying the equipment replacement or reducing funding beyond the current level will negatively impact the ability of employees to support the business and customers due to the increased risk of breakdown and lost productivity.

Other investment changes intended to reduce replacement would increase sustainment costs and the time to restore IT services. This is because technology beyond the vendor-supported life is normally outside of service agreements, and parts and labour are difficult and costly to secure.

Alternative 2: Refresh Per Plan (Recommended)

This alternative would strive to purchase and refresh MFA within asset life cycle guidelines.

New models are selected as part of technology refresh to meet user needs based on business requirements (USB Ports, Processing & Memory requirements, indoor versus outdoor usage, etc). Newer models provide additional compatibility with new business applications, operating systems, modern browsers, etc. The hardware refresh allows Hydro One to enforce service levels and performance based SLAs with vendors.

The option of renting/leasing MFA was reviewed. However, most of this equipment is made up of small, relatively inexpensive items whose usefulness is generally exhausted by end of life. Therefore it was deemed not feasible to rent or lease these items on a long term basis since leasing vendor margins would be purely accretive to the cost and would be higher than any cost of capital benefits from leasing. As a result, this alternative was not pursued.

Old equipment that is past the end of its useful life becomes unreliable and negatively impacts the ability of the business to perform their day to day work, thereby increasing costs to Hydro One and its customers. In addition, existing equipment may need to be upgraded to meet the changing needs and applications of the business.

Investment Description:

Hydro One's practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. Historically, Hydro One's refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

The estimated units to be replaced over the program are as follows:

	2018	**2019**	**2020**	**2021**	**2022**
Desktop/Laptop	1050	950	950	950	950
Printers	50	47	47	47	47
Other	21	19	19	19	19

Risk Mitigation:

Refresh programs run year over year, assets not deployed in one year are leveraged first the next year. Total number of machines deployed over 3-5 years remains constant.

Issues around software compatibility are addressed as part of certification process where a standard locked down image is deployed to all users with packaged/certified software applications.

Issues around hardware failure are addressed via the warranty process with the vendor.

Result:

The PC and Printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems, promoting workforce productivity.

Outcome Summary:

Customer Focus	• Support customer services by ensuring employees have the necessary equipment to meet customer needs.
Operational Effectiveness	• Maintain productivity by ensuring reliability of IT tools required by Hydro One employees to perform their daily work.
Public Policy Responsiveness	
Financial Performance	• Overall costs are minimized by enabling general employee productivity.

Costs:

Estimates are driven by historical costs, which are driven by the inherent lifecycle of the devices.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.1	1.9	1.9	1.9	1.9	9.8
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	2.1	1.9	1.9	1.9	1.9	9.8
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	2.1	1.9	1.9	1.9	1.9	9.8

**Includes Overhead at current rates.*

GP-05 Hardware/Software Refresh and Maintenance

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	20.1
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through Hydro One's call centre. The Enterprise systems also provide the backbone of business operations within finance, human resources, supply chain as well as asset and work management for the field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to customers and employees involved with the delivery of our customer service programs and work management programs linked to Hydro One customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

Investments are needed to build contingency so as to ensure that critical systems are available and can survive the failure (result of a manufacturer bug, security patch, etc) of any single supporting technology component. Investments in supporting technology components include telecom, IT hardware and software. Leveraging these investments with effective vendor maintenance means that the assets can be fixed and/or replaced expeditiously in the event of failure. To that end, Hydro One adheres to an IT industry standard practice of managing its assets through a lifecycle program ensuring vendor support is available and decreasing the likelihood of failure. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Alternative 1: Delay Refresh

This alternative would defer replacement of assets due for refresh and address additional issues with higher failure rates of the systems.

Increasing the current life-cycle asset refresh strategy takes Hydro One beyond industry practice and significantly increases risk to the business in the following areas:

- Increases in employee dissatisfaction and decreased productivity due to frequent and/or prolonged service outages;
- Degraded regulatory relationship from disruptions to market operations of IT systems that interact with market participants;
- Decrease in customer satisfaction due to failure of enterprise wide applications such as SAP, ihub/Tivoli, Microsoft Exchange, mobile applications, customer billing, relationship management, and call centre systems; to meet service quality index for customer service; and
- Productivity declines due to the high unit cost of supporting and servicing applications without vendor support.

Alternative 2: Refresh Per Plan (Recommended)

This would replace servers within life cycle guidlelines. A number of factors drive the refresh of an application. Hardware or Applications out of vendor support is one component, while additional application functionality or performance considerations will also drive a refresh. This investment covers the cost to build the new servers along with any data migration activities and decommissioning.

Server hardware is refreshed every 3-7 years based on hardware type. Hardware refresh is required to support enterprise applications from a performance/capacity and overall availability perspective to meet both customer and business expectations. Refreshing per plan allows for sustainment costs to be favourably negotiated due to technology improvements being implemented as part of new deployments.

This investment covers the capital costs, including Professional Services, to build new Web/Database/Application and Infrastructure servers along with all relevant data migration, Operating System, hardening, and decommissioning activities. There are a number of factors that drive hardware refresh – vendor supportability being a primary driver. There are other important considerations as well, including hardware age, and the general availability of supported replacement parts.

From an application perspective, today's business demands performance levels that are only offered by the latest server hardware and network technologies. While from a technology perspective, the entire IT market continues to virtualize and optimize key areas that are common across all data-centres – virtualizing server compute, storage and network. Refreshing this aging hardware allows for greater scalability and higher server densities, since it is possible to run addititional virtual servers with a smaller hardware footprint.

Investment Description:

Included in 2018 to 2022 the planned investments relate to the implementation of enterprise resource planning ("ERP") applications and related tools including SAP, further IT security access control and monitoring capabilities, middleware and databases, productivity tools, and server upgrades to keep the data center infrastructure vendor supported and to make improvements to the disaster recovery platforms. Refreshes for applications in sustainment are funded from this investment. The only exception is if the refresh is going to drive new functionality that can be tied to a Business Case. Lastly, a system being refreshed in order to accommodate its inclusion into the Disaster Recovery Program (DRP) would also be funded by this investment.

Risk Mitigation:

No concerns are foreseen with completing the completing the Hardware/Software refresh program. Any project risk is mitigated through stakeholders and modification of scope to reach desired business outcome.

Any risks around resourcing (specific skillset) will be addressed prior to project award with systems integrators. The award will ensure proper expertise is maintained during the life of the project and is well documented as part of scope execution.

Result:

This proactive investment approach reduces the risk of prolonged system outages and reduces the costs of unplanned investments for problem resolution. This investment in IT system reliability enables general employee productivity because users have access to the tools they require to work, and it enables customer satisfaction through availability of enterprise wide applications, customer call centre and outage management systems.

Outcome Summary:

Customer Focus	• Ensure IT Hardware / Software is supported and reliable to prevent information gaps for customers. Performance and Stability of IT Hardware / Software directly impact ability to service customers in a timely manner (ie: Outages, Billing Inquiry, Program Enrollment, etc).
Operational Effectiveness	• Maintain the reliability of IT Hardware/Software to allow applications / systems to function as designed and provide Hydro One employees with the information they require to perform their daily work.
Public Policy Responsiveness	• Maintain efficacy of the of IT systems that interact with market participants and support the IESO in its market oversight mandate.
Financial Performance	• Overall costs are minimized serves to reduce the potential for costly outages and unplanned refreshes or upgrades.

Costs:

Estimates are driven by historical costs, which are driven by the inherent lifecycle of the devices.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	3.9	4.1	4.1	4.1	4.0	20.1
Operations, Maintenance & Administration and Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	3.9	4.1	4.1	4.1	4.0	20.1
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**3.9**	**4.1**	**4.1**	**4.1**	**4.0**	**20.1**

**Includes Overhead at current rates.*

GP-06 MFA Telecom Infrastructure

Start Date:	Q1 2018	Priority:	High
In-Service Date:	Program	Plan Period Cost ($M):	6.7
Primary Trigger:	System Capital Investment Support		

Investment Need:

Hydro One has made significant investments in Enterprise class technology; most notably SAP, Microsoft and a Geographic Information System ("GIS"). These systems directly enable customer services such as timely and accurate bills and customer contacts through the call centre. The Enterprise systems also provide the backbone of Hydro One's business operations within finance, human resources, supply chain as well as asset and work management for its field staff upgrading and maintaining the power system. The reliability of these systems is critical to keeping Hydro One's business running effectively. The investment plan maintains the Company's Enterprise systems at service levels aligned with business criticality.

Key systems and the data generated will always be available (99.5%) to Hydro One's customers and employees involved with the delivery of the Company's customer service programs and work management programs linked to Hydro One Customer satisfaction goals/KPIs. Customer Information Systems enable effective delivery of call center, meter reading, billing, collections and settlement services to Hydro One Customers through reliable and cost effective information systems; Work Management Systems enable timely connection of customers and demand related activities.

This investment is required to replace end-of-life assets and to maintain service reliability and security, by refreshing network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source system, and upgrading the security solutions for external network interfaces.

Telecom infrastructure is the underlying hardware to support the business telecom network which is used to transmit data required to run business applications. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Alternative 1: Delay Refresh

This alterative would defer purchase of Minor Fixed Assets ("MFA") and deal with the incremental sustainment issues arising as a result.

Delaying the equipment replacement or reducing funding beyond current level will increase time between hardware refreshes, which may cause degraded voice and data network, reduced capacity to accommodate Move, Adds or Changes activities and poor network performance. Network availability and performance directly impacts customer interaction (ability to respond to customers in a timely manner in a call centre settings) and Lines of Business efficiency (performance from remote field sites will impact end user efficiency on applications as a result of poor network connectivity).

Alternative 2: Refresh Per Plan (Recommended)

This alterative would purchase and refresh equipment purchases according to their life cycle requirements.

Today's business applications demand the higher performance offered by current server and network technologies. The integration of systems, their applications, and sharing and dissemination of underlying data also drive higher complexities in order to fulfill expected business objectives and outcomes. In conjunction with this, from a raw hardware perspective, performance requirements also increase as more and more virtual servers are stacked onto fewer and fewer physical assets. Physical network bandwidth requirements increase proportionately in all these respects. Additionally, today's networking devices offer more mature degrees of network virtualization, and enable network segmentation and micro-segmentation which fulfills security requirements by further securing the data-centre environments.

Refreshing per plan allows HONI to deploy current generation technology in order to meet and exceed the demands put upon the underlying network technologies. For example, Move 2 Mobile project will rely on increased bandwidth from remote sites to ensure work being done is updated in SAP as quickly/timely as possible so the Company can reassign crews to other jobs if they are finished early. As Hydro One introduces new applications into its eco system, the aggregate need for more bandwidth increases. Current network technologies also allow for new functionality to be explored to further optimize network traffic making packet transmission more efficient and helping the prioritization of network traffic.

Investment Description:

The investment in Networks for voice and data is undertaken to replace end-of-life assets and to maintain service supportability, network reliability and network security. The strategy is to replace equipment that is no longer vendor supported. For network equipment, the refresh occurs about every five years for voice and data network related hardware. The funding for voice and data networks varies year to year depending upon hardware lifecycle refreshes, and incrementally as increasing business demands necessitate increased network bandwidth. As more business work flows are introduced and automated, there is generally always an impact to the underlying network. In other cases, additional workloads are pushed to remote field offices, which sometimes require a more efficient network infrastructure. In general terms, as business functionality increases and demand grows at a given Hydro One location (for example, Business Admin Support center (BASC) or an Operations (OPS) centre), network bandwidth is taken into consideration and if warranted, is incrementally increased to support the business. Costs in 2018 to 2022 reflect normalized refresh program covering Voice Networks, Telecom Networks, Data Centers and Perimeter Security.

Risk Mitigation:

All MFA assets are purchased in a just in time approach and in serviced in the same year of purchase. Any risk of assets not being installed will be managed as part of project scope with timelines being reflected in current or following year.

Result:

The Telecom Infrastructure refresh will provide a secure and reliable network to support core business applications, address Hydro One’s communication needs and maintain hardware supported levels required by our contractual commitments with vendors and outsourcing partners.

Outcome Summary:

Customer Focus	• Ensures reliable voice and data network to address Hydro One customer's communication needs to service customers.
Operational Effectiveness	• Maintain efficiency of the reliability of voice and data infrastructure to allow all IT applications to function as designed.
Public Policy Responsiveness	
Financial Performance	• Minimize overall cost to maintain its IT environment proactively and minimize the potential for costly outages and unplanned upgrades.

Costs:

Historical costs provide a trend and basis for budget estimation, in addition to vendor discussions for future demand management driven by development projects/programs.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.3	1.4	1.4	1.4	1.3	6.7
Less Removals	0.0	0.0	0.0	0.0	0.0	0.0
Gross Investment Cost	1.3	1.4	1.4	1.4	1.3	6.7
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.3**	**1.4**	**1.4**	**1.4**	**1.3**	**6.7**

**Includes Overhead at current rates.*

GP-07 Corporate Performance Reporting

Start Date:	Q3 2018	**Priority:**	Low
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	3.5
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

The Corporate Performance Reporting ("CPR") application is required to produce key high-profile, corporate reporting deliverables (e.g. OEB mandated reliability reports, reports to government, customer reports, and industry benchmarking reports) including SAIDI and SAIFI.

The Business has been using a custom, third-party software tool built approximately 7 years ago. It is still being supported by an external vendor. This tool is not supported by Corporate IT processes and Service Agreements.

There are limited knowledgeable resources available. As a result, it continues to incur costs and present unacceptable business reliability and continuity risks, unavailability of IT sustainment processes/agreements, and potential lack of vendor resource stability. There is limited availability of design and functional documentation on the algorithms, data sources and process chains. For a successful migration, any upgrade project must document these algorithms. This makes modifications for new requirements and standards difficult and risky to implement.

With the information contained on a stand-alone, proprietary system, resources in the Performance Management department are typically needed to fulfill other Hydro One Lines of Business ("LOB") with ongoing data requests. These requests can be labour-intensive.

Alternative 1: Maintaining the Status Quo

Maintaining the status quo leads to continued high risk and dependency on a custom, third-party application. In a qualitative sense, tight dependency on the limited vendor resources and limited support for a non-commissioned environment are high Business Reliability and Continuity risks given the importance of the data. Status quo will also keep Performance Management resources engaged in supporting other LOB's versus responding to new OEB requests and focus on core tasks and new LDC reporting requirements.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 2: Migrate Existing Servers into Commissioned Environment

The option to migrate the application and data servers used for the current Performance Management tools into the sustainment (commissioned) environment was reviewed. This would place the support for the functioning of the servers and their interconnectivity with Inergi under the Enterprise umbrella for day-to-day operational support. This alternative was rejected because it would not materially reduce risks.

In a qualitative sense, the primary drivers of Business Reliability and Continuity risk are the diminishing availability of qualified resource pool for the existing tool combined with the lack of documentation about the applications. Neither of these would be reduced by this alternative.

For quantitative analysis of lost benefits, refer to breakdown of savings indicated below.

Alternative 3 *(Recommended)*: Integration of CPR with SAP system

The plan is to transition the application and data to an enterprise supported platform (SAP). A Discovery phase was conducted to document the Business requirements and functional recommendations and to estimate costs and timelines for the delivery of this project.

The Quantitative and qualitative analyses of risk mitigation and benefits for the proposed project are summarized as follows:

1. <u>Business Continuity Risk:</u> The number of vendor expert staff who currently supports this program has shrunk down to two individuals. One of the benefits of integrating CPR into the SAP ERP tool is that internally trained FTE will support this program, further improving business continuity and lowering cost.
2. <u>Commissioned System:</u> CPR is a stand-alone application that is not integrated as a Hydro One enterprise application. Integrating CPR into SAP further improves its business continuity benefit.
3. <u>System Documentation:</u> Currently there is a lack of visibility of stored procedures (algorithms and logics) in the CPR program. Through this project, all such embedded algorithms and stored procedures will be documented and be more visible.

4. Optimization of Resources: Integration with enterprise SAP self-service tools results in avoidance of the current third-party vendor support (operational, maintenance and enhancement) costs.
5. Migration to an Enterprise Platform: will allow for a redistribution of Performance Management resources by allowing LOB's to access data directly from SAP. Performance Management Staff to join the "Planning" organization and engage in asset management and reliability related analyses particularly those focusing on new/evolving OEB and LDC reporting requirements.

Savings from the above are expected to be achieved beginning in 2020. These savings include a potential reduction in staff necessary to support the current program, avoided vendor enhancement work, and elimination of vendor annual support fees, which are currently $500k per year, (50% of which is attributable to Hydro One Distribution).

Investment Description:

This project is to build the new reliability reporting tools used by Regulatory / Performance Management teams. The project will involve the migration of the application and data servers and install new code into a sustainable SAP-BI solution to be used for the Performance Management functionality and rules. The project will also involve the migration of historic data, and leverage available SAP and enterprise tools including self service capabilities, reporting and other tools. In contrast to the current Oracle platform, SAP is a commissioned and fully supported environment.

The recommended execution plan will take approximately 18 months to complete both the distribution and transmission reliability components by the fourth quarter of 2019.

Risk Mitigation:

Business Requirements

There is no expectation of major gaps given the extent of the requirements and discovery workshops, however, it is possible and likely that new reporting requirements evolve and some details will require refining as the design and build steps move ahead. All issues will be addressed using standard SAP code. The plan will include provision for these and will address both time and cost implications.

Data Quality:

Early engagement and contact with the teams contributing to identifying data entities, data gathering, data conversion and data migration has to take place to monitor their progress and alignment to the CPR Delivery plan.

Solution Complexity:

The new tools will incorporate numerous, and in some cases complex calculations to derive the performance metrics. A concern is that the build may result in components of such complexity as to make testing and error detection difficult. The project team has to engage with the Vendor to build the new tools such that testing of each and isolation of the source of issues is readily possible. The plan will include provision for this and will address both time and cost implications.

Change Management

One of the goals for this project is to provide greater access outside of the Performance Management Team to reliability related data and scores via the enterprise self-service tools. Change Management is a key player to deliver the vision, training and job aids to the LOB's wishing to access this data.

Result:

Through the delivery of the Corporate Performance Reporting project, the following performance improvements would be achieved:

1. Stability and Optimization of Resource: The number of vendor expert full time employees who support this program has decreased from four to two individuals. One of the benefits of integrating CPR into SAP tool is that internally trained employees will support this program, further improving business continuity of this program. This will also optimize resource deployment in the Performance Management department.
2. Commissioned / Supported System: The current CPR tool is a stand-alone program that is not integrated as a Hydro One enterprise application and is not supported by Corporate IT processes and Service Agreements. Integrating CPR into SAP further improves its business continuity benefit.

3. Increased Visibility: The knowledge of stored procedures (algorithms and logics) in the CPR program resides with the third party. Through this proposed project, all such embedded algorithms and stored procedures will be documented and become visible.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Reduce continuity risk to the production of corporate performance metrics. • Improved efficiency and resource deployment by focusing on evolving reporting requirements.
Public Policy Responsiveness	• The outputs from the CPR system are frequently used for regulatory agency reporting (OEB & NERC & IESO & NEB), government agency reporting (Min of Energy), customer queries, and industry associations (CEA & NATF).
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the following application components and processes: Data Collection, Data Cleansing, Calculations, Reporting and Visualization.

The estimated cost was derived from the CPR Discovery work, in which Inergi was engaged to provide an estimate for the delivery work. At this time the estimate itself is high quality, however, it will be validated prior to submission of the business case to account for the time lapse between Discovery and Delivery phases (~ 4 years). Given the 10+ weeks of workshops to review the requirements; the gap is expected to be small and manageable.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	1.5	2.0				3.5	4.4
Less Removals						0.0	0.0
Gross Investment Cost	1.5	2.0				3.5	4.4
Less Capital Contributions	0.0	0.0				0.0	0.0
Net Investment Cost	1.5	2.0				3.5	4.4

**Dx components only and includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-08 PCMIS Modernization and Optimization

Start Date:	Q3 2019	**Priority:**	Low
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	1.6
Primary Trigger:	Cyber Security		
Secondary Trigger:	Reliability		

Investment Need:

The Protection and Control Management Information System ("PCMIS") tool is a critical platform used to support the Company's power system operations and ensure compliance with reliability and cyber security regulations. PCMIS is the single system of record for all Protection and Control ("P&C") device settings. PCMIS is utilized by Hydro One engineering, operations, and field personnel, as well as technical personnel in Local Distribution Companies across Ontario. The tool contains 'Bulk Electric System Cyber System Information' ("BESCSI"), sensitive data that must be strictly controlled and protected in accordance with Critical Infrastructure Protection regulations, as mandated by the North American Electric Reliability Corporation.

The primary function of PCMIS is to maintain device settings for the Intelligent Electronic Devices ("IED") that protect and control the grid. Over the years, PCMIS has been modified to meet various business and regulatory requirements, and has become a highly customized tool. The application and associated infrastructure are approaching end-of-life (EOL) and need to be upgraded.

PCMIS is a key Hydro One enterprise system that the company depends on to operate the Ontario electrical grid. In 2013, Accenture assessed the PCMIS platform and prepared a detailed report. The report highlighted numerous gaps in existing processes and significant deficiencies in the technology. System scalability, sustainability, and data integrity were all rated 'Poor'.

Alternative 1: Maintain the "Status Quo"

This option would have us leave the legacy system as is. However, maintaining the status quo and running an important application on unsupported infrastructure, exposes the company to the following risks:

- Inability to operate, repair, and replace critical P&C equipment;

- Failure to comply with cyber security regulatory requirements; and
- Failure to comply with reliability regulatory requirements.

Alternative 2: System Redesign and Replacement. (Recommended)

The planned changes will provide an opportunity to replace servers, operating systems, and databases with current technology to ensure operational and support longevity of the platform.

A modern PCMIS platform will be built on new infrastructure with secure, robust technology offering high availability (HA) and disaster recovery (DR). The PCMIS application will be replaced with fully supported commercial software. Functionality and integration interfaces will be optimized, consolidated with other Hydro One enterprise platforms or eliminated.

This is the preferred alternative, as this option will provide a modern robust system that will meet regulatory requirements. The company would like to address the project at the first possible opportunity, which based on available funding is expected to be in 2019.

Investment Description:

The project will maintain and further strengthen PCMIS as the single source of record for all P&C device settings. PCMIS supports users across the enterprise as well as engineering and field personnel in external utilities, providing centralized, controlled access to cyber-sensitive data. The system ensures that the configuration of critical grid protection systems is accurate and manages approval of any settings changes, supporting numerous key business processes including planning, construction, maintenance, repair, network operating and outage management. PCMIS data is used by the Distribution Management System ("DMS") to support advanced power system application analytics.

The PCMIS platform is aging and upgrades are required to the underlying infrastructure. This investment focuses on delivering a modern technological stable solution to address gaps in existing process and deficiencies in technology as highlighted in a recent third-party assessment. Processes will be optimized. Proven, secure technology will be implemented, resulting in a system that will provide years of efficient and reliable service.

The scope of this investment is to:

Replace existing PCMIS software and infrastructure;

Develop detailed system requirements and performance criteria. Design new infrastructure with proper development, quality assurance (QA), and DR environments. Build, setup, secure, configure, and test new infrastructure and integrate with secure, encrypted communication links. Assess available commercial software and select optimal solution. Purchase, install, configure, and test new PCMIS software.

Introduce process improvements and efficiencies;

Conduct comprehensive assessment of current processes. Working with the business groups we will optimize processes and leverage opportunities for consolidation with other Hydro One enterprise systems. Rationalize and eliminate customizations where possible.

Migrate data and launch new system.

Develop, test, and execute detailed data migration plan; provide orientation and training following proven change management principles; establish effective sustainment contracts.

Risk Mitigation:

To mitigate risk associated to the implementation of a new system and the time required to provide access and train all the LDC's, the 2 new and old systems will be run in parallel for a short period of time.

To mitigate risk associated with change resistance, the project will employ a full organizational change strategy. This will include the stakeholder management at the earliest stages, performing a change impact assessment and following resistance management plans will help secure buy-in from the user community.

Result:

The anticipated outcomes of this investment include:

- a fully supported platform,
- improved system redundancy and high availability, and
- optimized operational processes.

Outcome Summary:

Customer Focus	• Provide secure and reliable access to the protection and control information that will allow efficient system access support and maintenance.
Operational Effectiveness	• Ensure improved system availability. • Reduce system downtime and facilitate maintenance and upgrade work. • Improve access to critical configuration information allowing Hydro One and LDC's to be more responsive to operational issues.

Costs:

Cost estimates are based on historical costs of similar projects of this type.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets		1.6				1.6
Less Removals						
Gross Investment Cost		1.6				1.6
Less Capital Contributions						
Net Investment Cost		1.6				1.6

**Includes Overhead at current rates.*

GP-09 ECM Phase C

Start Date:	Q2 2017	Priority:	Low
In-Service Date:	Q4 2022	Plan Period Cost ($M):	2.1
Primary Trigger:	Public Policy Responsiveness		
Secondary Trigger:	Privacy		

Investment Need:

Enterprise Content Management ("ECM") is the technology used to capture, manage, store, preserve, and deliver content and documents related to organizational processes. ECM tools and strategies allow the management of an organization's unstructured information, wherever that information exists. Documents are centralized, searchable and retained or disposed as per requirements of regulatory bodies.

Hydro One is obligated to meet the requirements of many different regulatory bodies and programs with respect to document management. These include the North American Electric Reliability Corporation ("NERC") / Critical Infrastructure Program ("CIP"), the Ontario Energy Board, the Ontario Securities Commission ("OSC") and many others. Failure to meet these requirements will result in undue legal and regulatory risk for Hydro One.

Hydro One has commenced an Enterprise Content Management ("ECM") initiative comprised of three Phases.

- Phase A represents the classification of a majority of non-complex unstructured data. This was completed March 2015.
- Phase B (started November 25th, 2016 and is currently in progress) will develop several Proofs-Of-Concept (POC) offering options and alternatives for the implementation of records schedules (POC-1), email management (POC-2), management of physical documents (POC-3) and Records Management reporting (POC-4). Upon completion of Phase B, the proofs-of-concept will be configured for immediate implementation.
- Phase C will implement the POC across the company including records schedules, email management, management of physical documents and Records Management reporting (The purpose of this request is to seek funding to implement Phase C).

Alternative 1: Status Quo - Do Not implement Records Schedules POC

This alternative would not proceed with implementation of the Phase C Proofs of Concept and effectively defer the project indefinitely.

Maintaining the status quo is "high" risk because there are currently no records schedules (retention dates, disposition dates) activated on any Hydro One company record (emails and physical documents).

If the status quo were to be maintained, Records Schedules (retention dates, disposition/destruction dates) would not be affixed to physical documents or emails (company records). Without a "trigger" to demonstrate the requirement to retain company records or dispose of company records, Hydro One may be unwittingly storing company records that should be destroyed or inadvertently destroying company records that should be retained.

Alternative 2: Implementation of POC – 1 only

This alternative proposes the implementation of POC-1 only (records schedules POC only).

This strategy would not reduce the risk to Hydro One as the value of records schedules is in its application to company records. Records schedules need to be applied to company records as this POC cannot reduce company risk as a stand-alone product. The value of this POC is derived from its application to company records. As such, this alternative was eliminated.

Alternative 3: Full Implementation of Phase C (Recommended)

The recommended alternative is to proceed with the 3rd Phase of the ECM project - full implementation of all POCs including the implementation of records schedules, POC-1 (data retention dates, disposition activation, etc.) email management (POC-2) and physical document management (POC-3) and records management reporting and administration (POC-4) after the completion of Phase B. reporting and administration.

Investment Description:

ECM Phase C will result in the activation of records schedules including the retention, and destruction dates applied to the physical and email documents. In addition, dashboards demonstrating the growth in SharePoint usage and Open Text publishing (archiving) would allow Hydro One to monitor user adoption.

Risk Mitigation:

As ECM Phase C is the implementation of proofs-of-concepts developed in Phase B, there is a "risk" associated with the scalability of each proof-of-concept. Full implementation is the preferred alternative. However, there is risk associated with the cost to implement several solutions enterprise-wide. To mitigate this risk, the "actual" cost of implementation of POC-1 (data retention dates, disposition activation, etc.) will be reviewed and a "go-no-go" decision will be taken to determine if any or all addition POCs should be implemented.

Result:

Records Management ensures that institutional records of vital historical, fiscal, and legal value are identified and preserved and that regulatory mandated records are discarded in a timely manner according to established guidelines and identified legislation.

Benefits of Records Management include:

- More effective management, access and discovery of current records (both paper and electronic) and related enterprise content;
- Increased institutional accountability and timely access to information; and
- Greater adherence to regulatory requirements.

Outcome Summary:

Customer Focus	• Ensures the privacy, integrity of records and the security of record keeping processes.
Operational Effectiveness	
Public Policy Responsiveness	• Compliance with policy guidelines set by NERC/CIP and OEB.
Financial Performance	

Witness: Lincoln Frost-Hunt

Costs

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	-	-	0.2	0.9	1.0	2.1	3.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	-	-	0.2	0.9	1.0	2.1	3.4
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**-**	**-**	**0.2**	**0.9**	**1.0**	**2.1**	**3.4**

**Includes Overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-10 Work Management & Mobility

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	10.5
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

The existing processes and applications used to manage work within the Provincial Lines, Stations, Forestry and some central organizations involve significant manual effort and paper processing. This creates inefficiencies, time delays and data inaccuracies.

All work and information needs to be scheduled, dispatched, executed and reported through a standard set of processes and technologies across all of these lines of business within Hydro One. For example, the existing applications used by the Provincial Lines organization to schedule, dispatch and report work lacks the functionality and integration to support the productivity gains that are possible.

The "Move to Mobile" project to implement work management and mobility improvements for the provincial lines organization is presently underway. This was described in the investment summary document IT-05 ("Field Workforce Optimization and Mobile IT"), which was provided in Exhibit D2-2-3 filed in support of Hydro One Distribution's revenue requirement application (EB-2013-0416).

Alternative 1: Status Quo

This alternative was considered and rejected as a result of the following:

- significant, achievable productivity gains would not be realized;
- would continue to rely on manual and untimely paper processes for recording work accomplishments;
- data entry would remain labour intensive, and errors and poor data quality would continue to be prevalent resulting in multiple visits to the same customer site;
- dispatchers would not be able to leverage geospatial capability related to the location of assets, crews and work in order to achieve more work in any given day; and
- the existing mobile platform would remain inconsistent with SAP's future direction.

Alternative 2: Introduce Mobility across All Lines of Business in a Single Initiative

The development and implementation of a company-wide solution incorporating all LOBs and workflows was considered. The complexity of analyzing each component of the planning, scheduling, dispatching, work execution, closeout and reporting processes for key business scenarios for all LOBs within a single initiative would require a multi-year effort and a significant level of risk. It would also introduce a very large company-wide Change Management component related to business processes and applications impacting thousands of employees. This alternative was rejected due to its size, complexity, risk and timing.

Alternative 3: Move to Mobile Implementation Projects at Individual Lines of Business (Recommended)

This alternative involves the implementation of mobile technologies and related business process changes within the Forestry, Stations and Corporate LOBs in a number of discrete, focused projects over the next few years. Each of these projects contains elements of process change, coupled with enabling technology which will result in productivity improvements being realized as the process changes are phased in across each line of business.

Building on the experience gained in the Provincial Lines Move to Mobile Project and from other utilities, particular attention will be paid to the change management strategy. The expected benefits are highly dependent on the field workers wanting to use, and continue to use the new processes and technology over time.

This alternative will result in both quantitative benefits similar to those expected from the Provincial Lines project, and qualitative benefits within Customer Care.

Investment Description:

Through a competitive procurement process in 2014, the decision to standardize using SAP's mobile capabilities was made and a systems integrator was retained to help configure and deploy the solution across the Provincial Lines organization. The systems integrator is currently designing the improved business processes to be consistent with the industry best practices they have experienced working with other clients. A commitment to achieve at least a five percent productivity gain was established, with a projected return on investment of 21.3% and projected ongoing annual savings of $12 million. This project is currently under way with an in-service date in the first quarter of 2017.

Subsequent projects for Stations, Forestry and Corporate LOBs are expected to mobilize during 2017 and 2018, using the standard business and technical solutions established during the Provincial Lines project.

This investment will streamline Hydro One work management processes and deliver an enhanced, integrated scheduling, dispatching and mobile solution for the three lines of business, achieving significant productivity benefits in each.

The projects for Provincial Lines, Stations, Forestry and the Corporate LOBs involve implementing the following:

- SAP's mobile technology for use by Hydro One's field workforce;
- new/upgraded planning & scheduling software, integrated with SAP and the SAP mobile capability;
- SAP mobile platform integration with Hydro One's geographical information system (GIS); and
- Standardized processes for work planning, scheduling, dispatch, execution and reporting, as well as for company-wide processes such as purchase requisition and invoice approvals, timesheet preparation and submission, expense management, and workplace safety inspection form preparation and submission. This includes the monitoring and reporting of the expected benefits, and if these benefits are not being fully realized, initiating remedial action to help ensure the expected benefits are realized.

Risk Mitigation:

The major risks for these projects are similar to the ones faced by the current Provincial Lines "Move to Mobile" project. For example, field workforce acceptance of the new processes and technical solution; system performance of the technical solution; the post go-live approach to supporting the changes all have risks that must be managed. Experience gained during the Provincial Lines project is a major risk mitigation element for the follow-on projects. Any combination of these risks could result in a project in-servicing delay however the same approach used in the "Move to Mobile" project will be applied in these projects. They will be led and owned by the line of business, solid project governance, similar to that being practiced in the current Provincial Lines project will be applied to these follow-on projects. The projects will also take into account the relevant lessons-learned from Provincial Lines.

Following Project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The projects will be led by a field operations VP who is familiar with the culture and challenges associated with a process improvement implementation of this scale with the field work force.

Result:

These projects will provide the schedulers and field staff with real-time or near real-time work status update capability, present staff with a consolidated view of work information, provide a geographic scheduling tool on mobile devices, and enable timely, quality data capture at source.

These projects will also provide a near paperless and automated work environment which will help save paper and fuel, reduce vehicle emissions as well as save corporate operation expenses. Reducing manual steps and providing data validation at time of entry, will result in higher data quality and increased staff productivity.

In addition to a minimum five percent productivity gain for the Forestry, Stations and Corporate LOBs, there are also qualitative benefits in the areas of employee safety, customer service and employee engagement.

Outcome Summary:

Customer Focus	• Improved information reliability for customers with validation of data at source of input. • Improved service levels for customer-related processes like new-connects.
Operational Effectiveness	• Improve work processes by eliminating / automating as much of the manual & paper handling work activities as possible. • Increase efficiency by employing better scheduling and more efficient status of work accomplishment. Forestry, Stations and Corporate LOB should expect to see productivity gains of at least 5%.
Public Policy Responsiveness	
Financial Performance	• Reduce one-time costs including the mobility, planning & scheduling software.

Costs:

The following costs are based on previous experience with the first Work Management and Mobility project for the Provincial Lines organization which started in 2015 and which is planning go-live during Q1 2017.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	4.0	4.6	0.0	1.4	0.6	10.5
Less Removals						
Gross Investment Cost	4.0	4.6	0.0	1.4	0.6	10.5
Less Capital Contributions						
Net Investment Cost	**4.0**	**4.6**	**0.0**	**1.4**	**0.6**	**10.5**

**Includes overhead at current rates.*

GP-11 Enterprise Geographical Information System

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.5
Primary Trigger:	Efficiency		
Secondary Trigger:	Customer Value		

Investment Need:

Geospatial technology is a key information technology (I/T) infrastructure component that improves the effectiveness and efficiency of a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. While the technology is common to both distribution and transmission functionality, the investments and costs described in this document are specific to the distribution rate filing only.

Hydro One's current GIS software has been in place for roughly 15 years. Existing investments in the Enterprise GIS Program have enabled the integration of SAP and GIS achieving a synchronized, composite asset registry, including distribution and transmission assets, comprised of SAP and Hydro One's other major asset management systems. GIS infrastructure and software need to be updated periodically to take advantage of new functions and software performance improvements, and when possible to further enhance the technology to enable additional productivity in Hydro One's lines of business. All of the major vendor software components are reaching end-of-life during the planning period, and need to be replaced or upgraded. These products are no longer vendor supported after the end of 2017. Hydro One also proposes to address gaps and redundancies in business processes to author, maintain and utilize data from the geospatial databases.

Enhanced GIS functionality is needed to better support various business operations such as load forecasting, outage management, and protection and control, all of which help drive a more reliable network. The implementation of the unregistered easement public interface, for example, will reduce customer service staff effort to respond to numerous requests for assistance and complaints.

Increase in customer satisfaction and revenue are possible as more members of the public use the new easements search system. The integration of new customer-facing web maps would reduce calls to customer care to check rate class or associated concerns.

To summarize, the planned GIS work in the 2018 to 2022 period is comprised primarily of software replacement and / or technical upgrades, as well as moving the existing vendor (ESRI) software from the 10.1 to 10.4 version. One of the software components used for field design work (ArcFM) has reached end of life after 10 years in service and will be upgraded or replaced with a better / more cost-effective vendor solution.

Alternative 1: Status Quo

This alternative was considered and rejected because if this investment is not undertaken, the currency and quality of geospatial information will suffer and impact many key business functions.

For example, one impact of this is safety related. Up-to-date geospatial information resources assist safety practices as crews have easier access to accurate and timely views of the network model. Accurate GIS records complement HONI's Work Protection Code practices.

Alternative 2: Prudent Replacement of End of Life GIS Assets (Recommended)

Upgrade or replace the GIS system components and the integration between GIS and satellite systems it supports. Invest in new technologies that improve data governance and data quality, and leverage the GIS data to provide better and more useful information to the lines of business.

This investment is intended to both sustain the software at vendor release levels that the vendor is prepared to support, and to enhance the existing functionality through a series of projects from 2017 to 2022. Each project will be justified based on return-on-investment and related corporate objectives. Some of the planned enhancements are required to support the Work Management & Mobility investments for Provincial Lines and Forestry projects.

The proposal plans on the following:

- Software version upgrades to the vendor software that will no longer be supported after the end of 2017;
- Upgrade or replace the existing field design software (ArcFM) with a more modern package that provides better functionality and system performance at a cost per tablet lower than it is today;

- Conduct a discovery period to assess the value of implementing new SAP software that more seamlessly integrates Hydro One's map layers with the corresponding asset data in SAP; and
- Rationalize, where possible, the existing custom systems.

Investment Description:

The project will maintain and further strengthen Enterprise GIS as a single system of record comprising the location and connectivity of both transmission and distribution assets. GIS is the only technology that fully supports both logical connectivity and physical location of assets. It also supports asset properties and condition which facilitate planning and outage management, supports mobile workforce management through more effective crew routing, manages real estate records and Hydro One property, and provides the underpinnings of smart grid applications.

Over the years, as various asset-related systems have evolved at Hydro One, use of the GIS as system of record for location, connectivity and phasing has not always been respected. In some cases, complex bi-directional integrations have been built due to improper data governance practices and workflows. This investment focuses on remediating the inconsistent storage of location and connectivity between systems such as the Power System Database ("PSDB") and GIS as well as issues between the Customer Information System ("CIS") and GIS for storage of service point location. Both of these issues have led to increased cost to maintain overly-complicated integrations as well as the deterioration of data quality. Finally, some additional minor data governance issues with Health, Safety and Environment GIS data will be remediated.

Risk Mitigation:

For the version upgrade projects, lessons learned from a similar GIS software upgrade project that was carried out during 2012 and 2013 will be leveraged. This project was completed on budget and close to schedule, using some of the key Hydro One and Inergi resources who will be assigned to these projects. For the replacement of the field design software (ArcFM), an RFP will be issued to select the best value for replacement. Formal project delivery methodology will be applied to ensure adequate governance. The only known risk that could be considered significant is maintaining the data synchronization between the Corporate GIS data base and the SAP Asset inventory. The Information Technology Architects will be looking towards technology enhancements with SAP to centralize both the asset and GIS data in one location to minimize costs of maintaining data synchronization across multiple databases.

Result:

The core vendor software products will be upgraded during the period of this investment and, as is typical, will provide stability and the required level of vendor support for the next four to five years.

Outcome Summary:

Customer Focus	• Improved service to customers and Ontario property owners who should have access to information about outages and unregistered easements.
Operational Effectiveness	• Improved Decision Quality - Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions. • Improved productivity and reduced cost in both sustainment costs and labour.
Public Policy Responsiveness	
Financial Performance	

Costs:

The following costs are based on previous experience with the set of GIS software technical upgrades which occurred in 2012 and 2013.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	2.0	1.9	0.9	0.9	0.9	6.5	7.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**2.0**	**1.9**	**0.9**	**0.9**	**0.9**	**6.5**	**7.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.0**	**1.9**	**0.9**	**0.9**	**0.9**	**6.5**	**7.6**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-12 Business Process Consolidation

Start Date:	Q2 2020	**Priority:**	Medium
In-Service Date:	Q4 2021	**Plan Period Cost ($M):**	2.7
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The SAP Business Planning Consolidation (BPC) system is required to provide planning, budgeting, forecasting, and financial consolidation and reporting capabilities. The Investment planning maps projects & programs to specific strategic objectives. The budgeting process allocates funds to these investments. The forecasting process allows the company to track how the projects and programs are progressing.

The Business is currently using the BPC system which is a component of SAP Enterprise Performance Management portfolio and is designed to handle financial processes on a unified platform. The functional capabilities of the existing system are limited to project forecasting and legal and management consolidations.

Although Hydro One uses this application with available features, the system is not being used to its full potential due to numerous limitations. Specifically, enabled features do not support a fully integrated planning, budgeting and forecasting framework to enable continuous allocation of resources to support the business strategy and operational efficiency.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue its limited use of the BPC application. This is alternative does not allow for Hydro One to take advantage of process and operational efficiencies available through the application.

Alternative 2: Expand Use of BPC by Enabling Other Features and Functionality (Recommended)

This option would go ahead with implementation of the additional features available in the BPC application. Hydro One can continue to use the BPC system for project forecasting and legal consolidation and make use of additional functional capabilities that the system can enable, which are currently not being used.

This recommended option will allow Hydro One to fully realize the benefits of the BPC system by leveraging its potential of delivering planning, budgeting, forecasting, and financial consolidation capabilities in a single application. Hydro One will be able to adjust plans and forecasts, speed up budget and closing cycles, and ensure compliance with financial reporting standards. This in turn will bring about needed process and operational efficiencies.

Investment Description:

This project will provide enhancements to the current BPC system to become a unified & single planning & consolidation tool. It will add software and analytics features to realize additional business capabilities and benefits. These sought after capabilities include:

- What-if modeling and scenario planning to assess budget suitability in real time;
- Forecast models and to quickly update and adjust forecasts as needed;
- Automated aggregations, allocations, and other manual processes to speed up planning cycles; and
- What-if scenarios to allow the business user to identify quick course corrections.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

SAP BPC is a complex application and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

<u>Change Management and User Adoption</u>

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

Any combination of these risks could cause the project to be delayed and this will cause any of the following: Projects will be over-budget, behind schedule or will not deliver the scope it was intended to deliver. Solid project governance will be applied, taking into account the relevant 'lessons-learned' from other similar project in order to complete the project on-time and on-budget.

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities based on what-if analyses and scenario planning. It will improve accountability and planning accuracy. It will shorten cycle time, allows for financial information to be reported faster and align the company's plans with its strategic goals.

Outcome Summary:

Customer Focus	• Improve customer experience by providing timely budget and forecast data to the Business which will in turn improve the ability to manage programs and projects that affect customer-related investments.
Operational Effectiveness	• Improve decision-making capabilities and increase efficiency based on the ability to perform what-if analyses and scenario planning. • Improve accountability and planning accuracy due to shortened cycle time allowing for books to be closed faster.
Public Policy Responsiveness	• The outputs from the BPC system contribute to financial input used for regulatory agency reporting (e.g. OEB), government agency reporting (Ministry of Finance) and customer queries.
Financial Performance	• Improve financial performance and lower cost by reducing manual intervention.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management (such as training and job aids to the target user community wishing to access the new features), Project Management and Post Deployment. It includes vendor costs as well as direct LOB resource costs, and indirect costs of implementing the solution.

The cost estimate is based on a historical cost of enabling new functionality within the Consolidation Module of BPC. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One review process.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets			1.5	1.2		2.7
Less Removals						
Gross Investment Cost			1.5	1.2		2.7
Less Capital Contributions						
Net Investment Cost			**1.5**	**1.2**		**2.7**

Includes Overhead at Current Rates

GP-13 HR & Pay Related Technology Investments

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	5.0
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

The Human Resources ("HR") Division is responsible for a range of functions in support various processes and activities such as employee time reporting, board and travel recruitment, payroll, Offer Letter Creation and Processing, master data management and search, information for employees and managers as well as reporting of employee-related issues.

The current HR and Payroll functions utilize native SAP ECC system features and transactions to fulfill above mentioned functions and processes. Currently, there's significant reliance on manual, fragmented and inefficient processes and tools.

The existing HR application framework poses numerous challenges and features many inefficiencies such as: Inadequate Knowledge Database for staff, inconsistencies and confusion around the multiple templates to be used, inadequate Knowledge Base Self Service for Managers and Employees, lack of a Case Management/Ticket-Tracking System, lack of an Automated Workflow for certain processes, reliance on a multitude of workarounds and customizations that are costly to sustain as well as insufficient HR metrics and analytics.

Alternative 1: Status Quo

With the status quo option, Hydro One would continue to use the existing HR applications with their existing features.

This is not to Hydro One's advantage as there will be continued reliance on manual, fragmented and inefficient processes and tools. Also, this alternative would miss out on efficiencies and improved productivity opportunities.

Alternative 2: Implement Various System Enhancements (Recommended)

Hydro One would seek to leverage technology improvements and improve operational efficiency in the HR and Pay areas.

Hydro One will realize benefits such as a ticket tracking system for HR issues, a knowledge database for HR staff, managers & employees, automated letter creation & processing, an automated workflow for HR forms, mobility for HR applications, additional HR reports & analytics, online access to electronic pay advice and T4s, pay optimization, board & travel route optimization.

In addition, the intended enhancements will facilitate achieving the cultural change necessary to meet key strategic objectives.

Investment Description:

This investment is required to improve efficiency / productivity in the HR & Pay Area. This will be accomplished through 2 main initiatives.

<u>HR Process Optimization (start in 2018 & complete by 2019)</u>

This investment will address the following needs:

- Lack of a Case Management/ Ticket Tracking System for HR issues. In addition to improving the response time, this system will provide better insight into the types of issues coming to the HR Support Centre, which in turn allows HR to proactively respond to issues;
- Inadequate Knowledge Database for HR staff. By implementing a knowledge base comprised of answers to questions and solutions to problems from previous HR activities, this would reduce the amount of time spent by HR Assistants searching for information and thus improve response times;
- Inadequate Knowledge Base Self Service for Managers and Employees. This would provide quicker access to accurate HR information for employees and managers and minimize the time spent searching for information. Information will be more accurate and consistent;
- Manual Offer Letter Creation and Processing. This eliminates the requirement for multiple template letters to be drafted and maintained. It also reduces the amount of time involved in maintaining content for letters;

- Lack of an Automated Workflow for all HR forms/Smart Forms. A series of Smart Forms would improve efficiency and reduce errors in completing primarily by eliminating additional data input;
- Lack of Mobile Access to HR SAP applications. Mobile applications would provide HR Consultants, Managers and employees with more convenient access to information;
- Lack of Remote Recruitment Tool. Such a tool would reduce travel time for HR Consultants, Managers and employees; and
- Limited HR Metrics and Analytics. An analytics function would allow for improved reporting and analysis on HR issues to better inform decision making with clients.

<u>HR Pay - Phase 2 (start in 2019 & complete by 2020)</u>

Hydro One's payroll and master data management is managed using its SAP ECC system. Payroll business processes need to be further aligned with industry best practices and enhanced to fully utilize the available system capability for those processes which are currently administered through manual data entry. This investment is required to improve efficiency / productivity in the Pay and Time Reporting related processes by addressing the following needs:

- On-line Access to Electronic Pay Advice and T4s This would provide all employees an opportunity to access their pay advice and T4s online;
- Mobile/Remote Access for Time Reporting. This project would develop a mobile application that utilizes the Hydro One's SAP environment. The application will allow employees to access Time Self Serve (TSS) to input time via their smart phone or tablet and increase efficiency;
- Pay Optimization. HR would streamline current pay processes to utilize standard SAP functionality by removing workarounds and customizations that are costly to sustain; and
- Board & Travel Route Automation. This would allow the automatic creation of routes based on Google Maps. Routes are used to calculate amounts owing to Trades personnel to reimburse them for travel from home locations (or city centres) to assembly points.

Risk Mitigation:

<u>Solution Complexity</u>

HR and Pay Related Technology Enhancements are expected to be complex and finding the right skill set to support a successful implementation could be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and HR resources; all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to upgrade current HR and Payroll applications. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates. In addition, the project will be led by someone from the LOB who has deep expertise within the HR Process area.

Result:

This investment will yield operational efficiencies including enabling self-serve analytics and improved decision-making capabilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Improve HR performance by providing better insight to the types of issues coming to the HR Support Centre and better capabilities to address those issues. • Reduce travel time for HR Consultants, Managers and employees. • Allow for improved reporting and analysis on HR issues to better inform decision making with clients and with HR initiatives. • Allow for streamlined pay process & removal of work-arounds and customizations that are otherwise costly to maintain.
Public Policy Responsiveness	
Financial Performance	• Due to integrations in the system & better access to information, this translates to improved decision making abilities which in turn can lead to better financial performance.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as Hydro One direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex SAP changes. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.5	2.9	1.6			5.0
Less Removals						
Gross Investment Cost	0.5	2.9	1.6			5.0
Less Capital Contributions						
Net Investment Cost	**0.5**	**2.9**	**1.6**			**5.0**

Includes Overheads at Current Rates

GP-14 Warehouse Scanning Device Replacement

Start Date:	Q2 2018	**Priority:**	Medium
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	1.8
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

In order to effectively perform material and inventory handling operations, Hydro One has been using Bar Code technology at its warehouses since 2011. A barcode is an optical, machine-readable, representation of data. Using a scanning device (typically hand-held), the bar code is scanned and this provides information about the material such as type, quantity, price. As the information is automatically acquired through the barcode, it minimizes errors and increases speed compared to key entry. This makes operations at the warehouse more efficient.

By 2019, the current system will be at its end of life. As a result, there will either be limited or no vendor support for the scanning device and system that Hydro One uses. In addition, there have been many advances in bar coding technology that would make warehouse operations more efficient but the current system cannot take advantage of these improvements.

Alternative 1: Status Quo

This alternative continues to use the current equipment past its forecast end-of-life.

Maintaining the status quo leads to the business continuity risk of relying on a system and equipment that may no longer be supported by the vendor. Status quo is therefore not a recommended option.

Alternative 2: Upgrade Bar Code Technology (Recommended)

This alternative upgrades the bar coding equipment used at Hydro One warehouses.

By upgrading the bar code technology, Hydro One will be able to leverage improvements in technology in this area. It is anticipated that the technology will provide better tracking of inventory within Hydro One's Barrie Warehouse and Central Maintenance

Shop but also at the various remote field sites including offsite storage depots and construction project sites. This will bring about higher accuracy for tracking of available inventory.

Investment Description:

This investment will upgrade the bar coding devices used at the Barrie Warehouse & Central Maintenance with up-to-date mobile applications that sit atop the approved tablet infrastructure.

Risk Mitigation:

Solution Complexity

Upgrading the Bar Code Technology is expected to be complex and finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Supply Chain resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities.

Change Management and User Adoption

The goal of this project is to upgrade or replace its current warehouse scanning device with a more current version. This could potentially pose both process and technology challenges to impacted staff particularly at the Barrie Warehouse, Central Maintenance as well as several other remote locations as they learn to use the technology.

Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

In addition, the project will be led by someone from the LOB who has deep expertise within the Supply Chain and Warehouse area.

The timing took into consideration that the last time the bar code technology was implemented at Hydro One was in 2011. Typical software lifespan is 5 – 7 years. By 2019, it would already be time for Hydro One to upgrade to a more current version or replace its current warehouse scanning device with a new technology or solution.

Result:

This investment will yield operational efficiencies. By proceeding with this investment, Hydro One will be able to monitor its inventory with better accuracy and speed, leading to greater efficiency.

Outcome Summary:

Customer Focus	• Improve customer experience by providing efficient material availability to the Business which will in turn improve the ability to deliver timely programs and projects that affect customer-related investments.
Operational Effectiveness	• Provide accurate inventory count within warehouses and in remote field depots and construction sites.
Public Policy Responsiveness	
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on historical estimate of when Hydro One last implemented bar coding technology. When the discovery phase is complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	0.7	1.1				1.8
Less Removals						
Gross Investment Cost	0.7	1.1				1.8
Less Capital Contributions						
Net Investment Cost	**0.7**	**1.1**				**1.8**

Includes Overheads at current rates.

GP-15 SAP Treasury Implementation

Start Date:	Q2 2019	**Priority:**	Medium
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.7
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

Treasury Management includes management of enterprise's debt, cash and short-term investments, currency and derivatives exposures, with the ultimate goal of managing the Company's liquidity and mitigating its operational, financial and reputational risk. Common Treasury functions include cash flow forecasting, investment recording and settlements as well as financial reporting. Treasury functions support all lines of business at Hydro One.

Currently, the business operates on a Sungard Integrity v.8.2 platform while most of Hydro One's finance functions operate on the SAP platform. Vendor support for the current Treasury system (Sungard Integrity) ended in December 2016. The company needs to upgrade to Integrity v.8.5 by April 2017 in order to retain vendor support.

There are certain intercompany transactions generated by Treasury in Sungard Integrity that impact the general ledger in SAP. This interaction of data requires technical interfaces between the two different systems, increasing complexity and reducing processing time efficiency.

Alternative 1: Status Quo

This alternative would continue to use Sungard's Integrity application.

Integration between Integrity and SAP will continue to be via batch process rather than real-time. With real-time processing, data is processed immediately when it is received. As a result, data is more up-to-date and potentially more accurate as data can be accessed and corrected immediately by the user. Batch processing, on the other hand, takes time to process. If there are errors, these are typically not caught immediately.

Alternative 2: Implement SAP Treasury & Risk Management (Recommended)

This alternative proposes to replace Sungard Integrity with the implementation of a new SAP Treasury and Risk Management (TRM) module. The estimated cost for licensing is $1 million with an associated maintenance of $220,000 per year (22% of the license cost). Implementation costs were based (business case estimate) on a medium sized complex new SAP module.

The Licensing, implementation, and first year maintenance costs are considered to be a capital cost. Maintenance costs from year 2 onwards would be considered an OM&A cost.

This investment improves business performance through:

- Using standard SAP automated processes for cash and liquidity management, risk analysis and transaction management. Access to real time accounts receivable and accounts payable payment data in SAP will help improve cash flow forecasting and working capital management;
- Simplifying integration and movement of data with existing SAP core financial modules;
- Real time availability of data permits mitigation of issues and errors throughout the month rather than only at the end of the month. This will help Corporate Accounting meet aggressive deadlines;
- Reducing manual work by sending wire and EFT payments directly from SAP to the banks;
- Eliminating manual process in valuation of derivatives and managing exposures by direct feed of valuation data to SAP for financial reporting; and
- Timely update of bank transactions data in SAP for bank account reconciliations to identify any unusual transactions.

Investment Description:

The implementation of SAP Treasury & Risk Management includes the SAP modules: Cash and Liquidity Management; In House Banking; Bank Communication Management; Treasury and Risk; Hedge Management.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The implementation of the SAP Treasury and Risk Management module is expected to be complex and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Finance resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to replace its existing treasury system with SAP. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

Result:

This investment will yield operational efficiencies and improved decision-making capabilities. The SAP Treasury and Risk Management module will provide the Treasury department with a functionally complete set of solutions to support Hydro One's business. Being an SAP integrated solution will promote the harmonization of the system landscape and application rationalization. In addition, integrations between Treasury and other SAP modules will move away from batch processing towards real-time processing, which improves productivity, processing efficiencies and decision-making abilities.

Outcome Summary:

Customer Focus	
Operational Effectiveness	• Simplify the application landscape and integrate more tightly with the existing core SAP solutions. • Increase efficiency through reduced interface requirements, real-time data availability and the leveraging of recent technology upgrades in the SAP stack.
Public Policy Responsiveness	
Financial Performance	• Reduce reliance on IT support by migrating to a common enterprise platform that allows direct access data. • Improve financial management of Hydro One's debt, cash, short term investments, currency and derivatives.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs, as well as Hydro One's direct and indirect costs of implementing the solution.

The cost estimate is based on historical business case estimates of a medium size, complex new SAP module. When discovery phases are complete and vendor quotes received, a more accurate project cost estimate will be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are appropriate. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	1.5	1.2	-	-	2.7
Less Removals	-	-	-	-	-	-
Gross Investment Cost	-	1.5	1.2	-	-	2.7
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	-	**1.5**	**1.2**	-	-	**2.7**

Includes overheads at current rates.

GP-16 Customer Self-Service Technology

Start Date:	Q2 2019	**Priority:**	High
In-Service Date:	Multiple	**Plan Period Cost ($M):**	12.9
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Self-serve technology has now become common in our society - from banks which offer ATM machines to grocery stores where a customer can scan purchases and make payments without going through a cashier. For the customer, this is convenient and often saves time. For the company, this fosters increased productivity and cost savings. Offering these service capabilities is rapidly becoming a demand from customers and a necessity of doing business.

Hydro One can provide similar convenience to its customers. Customers can view their bill, understand their usage, find out what conservation tools are available to them, submit a meter reading when communication is unreliable, report outages, pay bills and many other activities; all online. This improves customer satisfaction and engagement. These offerings may also represent a time-saver compared to having to call the call centre. From the Company’s perspective, by empowering customers with self-serve technology, this improves productivity through a reduction of the volume of calls into the call centre. This can then be factored into future outsourcing arrangements.

Mobile access is a key channel going forward. In 2016, 40% of customers accessed Hydro One’s website on their mobile device. This number is expected to grow over the coming years as new technology is introduced.

Hydro One does offer certain online services to its customers currently. These include:

- HydroOne.com - Hydro One's corporate website provides customers with safety education, energy conservation tools, a breakdown of their bill, payment options, conditions of service, etc.; and
- Mobile App - Hydro One's current mobile app provide information on power outages, including number of customers and affected estimated restoration time.

These offerings are high value. However, customers are saying that they want more of these services. For instance, the ability to send meter readings by uploading a photo of the meter read, the ability to report power outages through a mobile phone and the ability to pay bills through mobile application.

The customer facing infrastructure used by the current online system is aging. If Hydro One were to offer enhanced online services, the current infrastructure would be inadequate to ensure that customers accessed the material in a timely and efficient manner. High system latency and insufficient bandwidth would negatively offset the benefits of offering the new features and could even cause customer satisfaction to be negatively impacted.

Alternative 1: Status Quo

This alternative would stay with the current suite of online tools and not introduce new self-serve capabilities.

If the status quo alternative is selected, although this would not have any impact in terms of reliability of the distribution of electricity, Hydro One would likely experience deterioration in customer satisfaction. Without enhancing the usability of these self-service tools, Hydro One will not realize benefits associated with greater use of self-service channels. Aging infrastructure and software which are no longer under vendor support would pose an unacceptable risk to Hydro One.

Alternative 2: Upgrade Existing Self-Service Technology (Recommended)

This alternative would implement new self-serve technologies in the Customer Service area.

This alternative is recommended since this will improve customer service and maximize the ability of the company to establish a digital channel. This alternative will allow Hydro One to easily increase capacity of the solution as additional customers leverage web based, self-service solutions across multiple devices. In terms of the impact to the customer rate, the cost to implement this investment will be partially offset by operational savings gained by implementing this technology.

Investment Description:

This investment is required to upgrade customer self-service technology to enhance the customer experience and upgrade the underlying technology since it has reached the end of its useful life.

This investment will cover rolling out various mobile application enhancements in 2019 and 2020. These include providing customers the ability to send meter readings by uploading a photo of their meter reading.

This investment will also provide funding for website upgrades and enhancements in 2022. Hydro One is currently upgrading & enhancing its website in 2017 to provide a better digital customer experience. This new website that will be rolled out in 2017 will be mobile-friendly, will provide customers ability to access an interactive bill, will provide interactive tool to assist with energy conservation, will make it easier for customers to submit and track service requests. However, as technology evolves and as customers' needs grow and change, by 2022, this website will already be out-dated and will require another round of upgrades.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

The timing of this investment is based on the useful life of the existing technology and the need to ensure the self-service tools remain relevant and up-to-date.

Result:

This investment will allow customers to interact with Hydro One via their channel of choice and better manage their electricity usage, thereby increasing satisfaction.

The solution will enable customers to conveniently access information, services, and transactions online, in an easy-to-use and intuitive manner, using both mobile and conventional desktop access.

The new technology will increase adoption of self-service channels by providing customers with additional self-service options, thereby reducing call centre interactions. A mobile first design approach will also ensure that our customers can access the website using the technology of their choice.

The new mobile application will allow customers to report outages and will potentially include other functions, including meter reading, payment options, and billing history to provide another avenue for customers to interact with Hydro One.

Outcome Summary:

Customer Focus	• Improve customer engagement by providing a mechanism for customers to conveniently interact with the company. • Provide customers a streamlined online and mobile experience.
Operational Effectiveness	• Increase in productivity since call centre agents can focus on helping customers with issues that can't be addressed via self-serve technology. • Reduce risk of operating on an aging infrastructure and software which are no longer under vendor support.
Public Policy Responsiveness	• Promote government policy on energy conservation by providing consumers easy access to information and interactive portals.
Financial Performance	• Minimize costs by reducing calls to the call centre.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost, as well as indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized after a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets		2.3	1.4	2.3	6.9	12.9
Less Removals						
Gross Investment Cost		**2.3**	**1.4**	**2.3**	**6.9**	**12.9**
Less Capital Contributions						
Net Investment Cost		**2.3**	**1.4**	**2.3**	**6.9**	**12.9**

Includes overheads at current rates.

GP-17 S4 HANA for Finance

Start Date:	Q2 2020	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.4
Primary Trigger:	Operational Effectiveness		
Secondary Trigger:	Financial Performance		

Investment Need:

IT Need
SAP has announced that they will stop improving the current enterprise BI platforms immediately and vendor support for the current platform altogether will end in 2025. SAP will shift development to their new SAP S/4 HANA platform. All business functions performed on the current platform will ultimately have to migrate to the new platform.

Business Need – Finance
Multiple systems are required to produce the monthly financial statements at Hydro One. They include SAP BI, SAP ECC, SAP BPC and MS Excel. This drives delay and complexity into the month end processes.

The company faces higher requirements for financial reporting and has a need for improved month end, quarterly and year-end financial reporting procedures and processes.

SAP has, over the past 3 decades, created a platform that can be configured to perform any one business function in multiple ways. While "best practice" has always been built into every SAP transaction, user interpretation of what data needs to input has led to inconsistent transaction processing and erroneous or missing data. SAP has re-architected the Enterprise Resource Planning (“ERP”) system, consolidated into ERP the financial functions that currently reside on the BI system, streamlined the financial consolidation processes and simplified the reporting functions. Business Planning has been moved from BW (business warehouse) and incorporated directly into the SAP ERP platform. This means that the impact of planning changes can be immediately reviewed.

More recently, further improvements have taken place in the continued simplification of processes that removes the need for data replication. This provides end users with faster access to data to generate real time reporting and ultimately reduce the time to close the books by 10 – 20% according to SAP estimates. Additionally, new systems provide the ability to facilitate predictive forecasts and dynamic simulations using real time data to provide greater reasonability to the numbers. Embedded predictive algorithms and simulation capabilities enable management to better monitor and forecast business needs.

Alternative 1: Status Quo

This alternative would continue to use the current BI and ECC platforms in conjunction with other applications to produce statements and reporting.

IT

The current SAP platform will reach end of life status, by 2025 at which time SAP will cease providing any support for the current platform.

Business

Continue to plan and manage and report financials in less than optimal manner.

Alternative 2: Replace SAP with an alternative software system

This alternative would replace the current SAP BI platform with competing ERP software and/or adopt a multi-vendor approach by replacing the various business functions with Commercial off-the-shelf (“COTS”) applications.

Not justifiable due to the investment Hydro One has made in SAP.

Alternative 3: Migrate to the S/4 HANA platform (Recommended)

IT Benefit

Migrating to S/4 HANA will ensure continued vendor support to reduce IT costs and ensure ongoing, timely performance.

Business Benefit General

Hydro One has significant investment and experience in implementing and maintaining SAP. Over the past 10 years, Hydro One has consolidated over 130 applications, and the functions they performed, into SAP leading to IT and business process savings.

S/4 HANA is proven to offer superior query performance, faster load times thus increasing performance in the numerous business areas that use the ECC platform.

S/4 HANA has a streamlined user interface which has been built upon the same design concept that most mobile applications use which is to present the user with exactly the data they require and limit input options. On the S4 HANA platform business functions or processes have been simplified resulting in less time required to perform the associated processes and improved data quality. The database structures have been greatly simplified. SAP has done away with the sub ledger/ledger construct thus increasing performance.

Business Benefit Finance

Over and above the general business benefits finance functions such as business planning, consolidation and disclosure, financial accounting and financial reporting have been consolidated on the S4. This will reduce the time required perform many of the finance processes.

Investment Description:

Planned investments include HANA which is SAP's new database technology; S4 which is SAP's new application software, SAP's new software configuration guides. This investment will also include, but is not limited to: integration with other enterprise systems; and data migration of financial data from the existing ECC to the new S4. With S4 Finance the business planning and consolidation (BPC) functions that used to be performed on SAP BW have been incorporated into S4 Finance. Data will have to be migrated to S4 from ECC and BPC. When complete all Finance functions can be performed in S4. The S4 version of BPC offers improved plan and forecast capabilities.

This investment will not be impacted by other investments such as SAP Treasury, Business Planning and Consolidation and others. However, it should be noted that anything added to SAP through some other investment will ultimately have to be migrated into SAP and implementation collisions must be managed.

Risk Mitigation:

Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project milestones. The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

The SAP HANA delivery is expected to be a complex implementation and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience & expertise to complete the work successfully.

Configuration guides will remove significant amounts of implementation inconsistency normally introduced by 3rd party implementers.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP, and Enterprise Architecture resources. All of these resources are integral to success of the project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Any combination of these risks could result in a project in-servicing delay. To minimize the risk, solid project governance will be applied taking into account the relevant lessons-learned from other similar projects.

Result:

This investment will yield operational efficiencies, improved decision-making through real time reporting, process simplification, better data driven by standard and consistently performed transactions, better user adoption due to a simpler and modern interface.

Outcome Summary:

Customer Focus	• Leverage out-of-the-box, customer functions that represent the full spectrum of utility customer interactions.
Operational Effectiveness	• Increase operational effectiveness through simplified user interfaces, superior performance and more consistent processes. • Drive opportunities for cost savings through leaner processes and in-platform planning and reporting
Public Policy Responsiveness	• Improve capability to meet statutory reporting capabilities.
Financial Performance	• Reduce the inconsistencies in month end reporting through simpler user interfaces and consistent process execution.

Costs:

The underlying premise is that S/4 HANA will help us fine tune what we have today, not reinvent it. This will extend the investment in the current SAP ERP that was implemented in phases between 2008 and 2013. The cost estimate for this investment assumes the use of the standardised configuration and that the project will be based on migrating data from our existing ERP platform to the new S/4 HANA platform, without the need for lengthy business requirements gathering and interpretation. This is what commonly results in very expensive SAP implementations.

Hydro One will also launch an open competition so multiple vendors can submit their proposals and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets			1.2	1.7	3.6	6.4
Less Removals						
Gross Investment Cost			**1.2**	**1.7**	**3.6**	**6.4**
Less Capital Contributions						
Net Investment Cost			**1.2**	**1.7**	**3.6**	**6.4**

Includes overheads at current rates.

GP-18 Integrated System Operating Centre

Start Date:	Q1 2015	**Priority:**	High
In-Service Date:	Q3 2020	**Plan Period Cost ($M):**	56.4
Primary Trigger:	Asset Driven – Failure Risk & Capacity		
Secondary Trigger:	Regulatory		

Investment Need:

The Network Operating Divisions ("NOD") Backup Control Centre ("BUCC") facility was placed in-service in 1956, and is the means that regulatory, business and operational requirements are sustained for monitoring and control operations to North American Electricity Reliability Corporation ("NERC") standards, Distribution and Transmission System Code ("DSC") requirements and Hydro One standards respectively. The BUCC facility consists of the building, computer tools and systems that support Operations in the event of a partial or total loss of the primary Ontario Grid Control Centre.

A risk of future extended outages, inability to execute necessary upgrades /replacements and increase capacity to required computer systems and tools, could result in significant disruption to business continuity and Hydro One's ability to meet customer's service level expectations. The facility is currently at capacity in computing space, HVAC, power and due to the age of the structure, among other factors, remedial efforts are either not viable alternatives, cannot be mitigated or are cost prohibitive to execute. In addition, a prolonged activation would impede supporting Operations; i.e., Outage Planning, Operations studies and support due to a lack of back office support space. Current Operations support groups that are fundamental in daily Operations, are unable to occupy the BUCC during any event, and would require current staff at the Richview facility to be relocated, procurement and set up of required computer equipment and would take vital time to implement.

Alternative 1: Status Quo/ Use Offsite Leased Space

Hydro One Network Operating maintains the existing Control Room, and Security Operations maintain existing facilities. A new offsite leased Data Centre facility (to mirror capacity of OGCC data centre based on 20 year lease and initial setup costs) could be provisioned and additional office space would be required and furnished for prolonged activations. This alternative includes additional leased space for the Backup Integrated Telecommunications Management Centre's ("BUITMC") control room and compute needs.

The total cost of this option is estimated to be $78M, of which, the distribution portion will be 50.07%.

This alternative has been rejected as the current BUCC for Network Operating and the Backup ITMC do not meet operational requirements.

- The current facility imposes a high level of risk to both regulatory compliance and, Hydro One's reputation and customers, if any failures are experienced.
- This alternative fails to provide for the Security Operations Centre's ("SOC") need for an adequate primary control centre.
- Even with extensive investment in the existing facilities, this option does not adequately remediate all risk factors (e.g., basement flooding, power capacity constraints, electrical hazards due to proximity to TS).
- This alternative cannot accommodate current or projected growth, requiring further investment in leased facilities in the future.
- This alternative would require the relocation of the existing compute space and critical support infrastructure, currently housed at the BUCC, to a new leased BUITMC.
- This alternative cannot mitigate all known risks due to site conditions, size and location. In the event of a prolonged activation, some existing staff of the Richview facility would be asked to leave to make space for operating activities, and even if this arrangement can be made, there is not sufficient onsite parking, work space, or basic facility infrastructure for the overflow of staff.

Further information relating to the rejection of Alternative 1 is found on pages 22-24 of this Investment Summary Document.

Alternative 2: Build NOD Backup Control Centre and Data Centre exclusively.

This alternative was reviewed in light of the 2013 Toronto rainstorm and ensuing flooding that occurred in the GTA. This event required the ITMC to activate the BUITMC located in Kitchener Ontario. During this event, it was made apparent that a failure in the ITMC function or delays in Backup activation, created an inability to remediate, troubleshoot telecommunication outages, and had a significant impact on Network Operating's ability to monitor and control. Loss of communications had severe impacts on the Control Room's ability to monitor and control field assets and clearly showed that a new NOD Backup Control Centre and Data Centre would not remediate all risks currently identified. This alternative proved that a more robust BUITMC is required.

Due to the importance of the ITMC, the identified need for a new BUITMC and the economies that would be foregone with this alternative, this alternative was removed from further consideration. The estimate for this alternative is $104.8M, of which, the distribution portion will be 50.07%.

Alternative 3: Build Backup Control Centre's for Hydro One Networks and ITMC including shared critical infrastructure, back office support areas and an integrated Data Centre.

This alternative includes Control Rooms, an integrated Data Centre and shared back office support areas for prolonged activation and is considered the minimum requirement to address known operational risks that currently exist. This alternative also includes the purchase of the preferred site. This alternative is estimated at a cost of $124.7M, of which, the distribution portion will be 50.07%.

While this alternative meets Network Operating and the Integrated Telecommunications Management Centre's minimum requirements, it has been rejected as it fails to maximize investment utilization through synergistic lines of business occupancy as well as shared use of critical infrastructure. The incremental cost of the SOC inclusion is $ 6.5M. This also fails to take advantage of operation synergies for operational response to security threats, both physical and cyber.

Alternative 4: Acquire an existing facility that could be retrofitted / utilized to accommodate NOD Backup Control Centre, BUITMC and an integrated Date Centre.

A market assessment was completed that reviewed potential sites against identified requirements for size, location, travel times, power infrastructure, telecommunications and occupancy. This also included an internal assessment of Hydro One owned sites. At the completion of the assessment, it was determined that no suitable site was available in the market or within Hydro One's owned locations. As a result, this alternative was excluded from further consideration.

Retrofitting an existing facility was also considered. In order to suit the environments and critical support infrastructure required for Data Centre reliability, real time 24x7 Control Rooms, Security considerations including dual power supply and telecommunications expansions, extensive investment would be required. At the time of the assessment, no suitable site / facility was available and as such it was removed from further consideration. In addition, the total cost to retrofit was anticipated to be equal to or greater than greenfield construction and as such was removed from further consideration.

Alternative 5: Build ISOC with incremental capacity for a Primary NOD Control Centre, SOC Primary Centre, and BUITMC including an Integrated Data Centre, Shared critical support infrastructure and back office support space.

This option involves building the ISOC as described in alternative 6 and making the necessary arrangements to utilize the ISOC as the Primary Operating Control Centre from Day 1. The OGCC, which is the existing primary operating control centre, will then be converted to be the backup centre.

The additional cost for the building, site and the uplift / upgrades to current mission critical Operating systems and IT architecture to initiate the ISOC as a primary NOD Control Centre, from inception, was determined to be high when weighed against the initial benefits; therefore, this option was rejected. The total cost of this option is estimated to be $141.9M, of which, the distribution portion will be 50.07%.

A strategy to enable a "Dual Control" operational strategy was pursued in an effort to leverage current upgrade investments for their useful life. This alternative does not facilitate the Dual-Control strategy and, without costly upgrades, there will not allow the transition to occur in a more organic nature, representing less cost impacts and less disruption to the Operating functions and staff.

Alternative 6: (Recommended) Initiate Build of the Integrated System Operations Centre (ISOC).

This alternative provides for:

1. a Network Operating Control Centre;
2. a Backup Control Centre for the Integrated Telecommunications Management Centre; and
3. primary facilities for Security Operations.

This Alternative also includes the provision for a shared integrated Data Centre, all critical support infrastructures at the preferred site. This alternative will maximize Operational flexibility for Hydro One Networks and associated lines of business while eliminating the need to duplicate investments in multiple sites, and costly critical support infrastructure (emergency generators, uninterrupted power supplies, telecommunications etc.). The total distribution share of this option is estimated to be $64.6M, and the specific amount for this plan period would be $56.4M.

The ISOC strategy will enable a "Dual Primary" scenario where both Centres can be live as compared to the current live/passive (standby) model. Functionality required to facilitate this strategy is not expected until 2022 and will be implemented within current/future lifecycle schedules for the primary applications (i.e. ORMS, DMS, NMS etc.). This effectively negates the need to prematurely replace, re-architect and implement newer systems prior to their lifecycle expiration while providing the benefits and future flexibility of Primary Control ability.

Further details about the project are included in Appendix A.

A detailed option comparison is included in Appendix B.

Investment Description:

The Integrated System Operations Centre will house multiple lines of business through the provision of dedicated Control Centres: an integrated Data Centre and shared back office areas. This facility will be a hardened facility employing emergency preparedness criterion, industry best practices that meets physical and cyber security standards. This strategy provides flexibility for Hydro One Networks to enable future dual control through a systematic and cost effective approach with planned lifecycle upgrades. These facilities are essential in maintaining adequate redundancy for Operation of the Bulk Electric System, management of the Distribution network and associated customer responsiveness (i.e., outage and storm management). In addition, this will ensure Telecom Communication Network management and adherence to mandated North American Electricity Reliability Corporation (NERC) requirements for Emergency Operating Procedure 008-1 "Loss of Control Centre Functionality". It ensures achievement of reliability and availability targets commensurate with the criticality of these facilities. The ISOC will provide in house security operations, mitigating reliance on third party services and provides needed compute capacity for Security Event Monitoring (SEM).

The ISOC design provides the following:

<u>Facility:</u>

- Provide NOD with a new backup control centre including a control room, back office space and a shared data centre, employing the following strategies; provides the operating flexibility that allows Network Operating to duplicate the current OGCC functionality mitigating the current heightened risk profile with the current BUCC.

- Provides additional training synergies through the use of simulation technologies, allowing use of the facility while not required for backup activation (dual purpose).
- Enables future dual control potential, increasing the readiness and customer response times for any future event that may impact the Ontario Grid Control Centre and NODs ability to manage, monitor, control and dispatch on the distribution system.
- Ensures security requirements, both physical and cyber, including a hardened facility to guard against physical and environmental threats (i.e., tornadoes).
- Provides the ITMC with a new backup operations control centre including a control room, back office and integrated computing facilities mitigating the current risks at the BUITMC and the risks a failure of ITMC Operations poses on Network Operating.
- Provide the Security Event Management centre with needed integrated computing facilities.
- Provide Security Operations with a headquarter location including a control centre, office space, investigative rooms, emergency operations centre (room) and integrated computing facilities.
- Shared and redundant critical support infrastructure.

The total distribution portion cost of the construction build, including contingency and escalation, is estimated to be $43.3M.

Site:

Provides a 16.4 acre site in Orillia Ontario at a cost of $3.0M, and 50.07% of this is the total distribution portion cost. The site was selected based on an extensive Market Assessment in Q1 of 2015. The Orillia site met essential criteria, and included material advantages and associated cost savings in terms of; location, current site development activities completed, forgoing of water detention requirements, improved commute and activation times, and significant municipal development charge savings realized through the Industrial Development Charge Moratorium offered by the City of Orillia.

Architecture and IT design:

The detailed design is expected to be completed by the middle of 2017. The distribution portion of the total engineering and IT consultant costs, for the detailed design, is estimated at $7.7M.

Connectivity and Telecommunication:

Connectivity and SONET at the new ISOC facility allows the ISOC data center to communicate with the OGCC and the rest of the Hydro One telecommunication network. The distribution portion cost to establish this communication connectivity and SONET is estimated to be at $6.8M.

Network Infrastructure:

Lastly, an additional $5 million (distribution portion only) has been budgeted for IT infrastructure. This covers the cost associated with connecting each individual workstation console to the ISOC data hall.

Compliance

In order for Hydro One Network Operating to be compliant, there are many requirements, Regulatory Standards and internal Hydro One Standards that must be satisfied. In addition, industry best practices are respected to build on reliability and availability of critical system. The ISOC investment must adhere to; but not limited to the following:

1. North American Energy Reliability Corporation (NERC) –EOP-008 "Loss of Control Centre Functionality" necessitating backup activation to be equal to or less than two hours.
    a. In a related Federal Energy Regulatory Commission (FERC) order (Docket No. RD11-4-000 at 14) FERC signalled its concern that the two hour activation requirement is too long and that "it is imperative that full backup functionality occur as soon as possible after the loss of primary control functionality". FERC also noted that "…it may revisit this transition timeframe". This signalled that the new BUCC facility must take into consideration that activation timelines could be reduced in the future.
    b. NERC and FERC also require the Backup to be "capable of operating for a prolonged period and providing functionality sufficient to maintain compliance with all reliability standards that depend on primary control functionality."
2. Restoration Participant Attachment as required by the IESO administered 'Market Rules' for the Ontario Power System Restoration Plan (OPSRP).
    a. The BUCC is listed as one of the key facilities which comprise Hydro One's contribution to the Ontario Basic Minimum Power System.

3. Required as per EOP-005-2 NPCC-D8 (NPCC Directory 8) and IESO Market Rules & Manuals (Market Rules Chapter 5 – Power System Reliability, Market Manual 7: System Operations, Part 7.8: Ontario Power System Restoration Plan.
4. NERC Critical Infrastructure Protection (CIP) Requirements – ensuring assets are protected logically (electronic security perimeter) and physically (physical security perimeter).
5. Communications: NERC & IESO Market Rules:
   - NERC-COM-001-2;
   - Chapter 2, Appendix 2.2, Section 1.1.4- Technical Requirements: Voice Communication, Monitoring and Control, Workstations and Re-Classification of Facilities;
   - Chapter 2, Appendix 2.2, Section 1.2.3 – Transmitter Submission to the Energy Management System;
   - Chapter 5, Section 12.1.1 – Voice Communications Methods;
   - Chapter 5, Section 12.1.6 & Section 12.2.12 – Alternatives During Loss of Communications;
   - Chapter 5, Section 12.2.3 – Required Voice Communication Facilities;
   - Chapter 5, Section 12.2.4 – Voice Communication Reliability;
   - Chapter 5, Section 12.2.11 - Voice Communication Monitoring and Testing; and
   - Chapter 5, Section 12.3.2 - Required Data Communication Facilities.

Additional Design Criteria

In addition to the above requirements, the following Industry Best Practices have been incorporated into the ISOC design:

- Designed for Dual Hot Centre's with Increased Security
  - Provides additional functionality that improves operational proficiency;
  - Improved system security and redundancy; and
  - Meets minimum provincial anti-terrorism standards (i.e., blast protection).
- Multifunctional Facility / Business Continuity
  - Increased building utilization (multipurpose, real time, simulation and future Dual Control);
  - Operational flexibility and scalability (modular expansion); and
  - Emergency Preparedness criteria – facility separation for common mode failure.
- High Availability / Reliability 99.95%
  - Employing an Uptime Institute guiding principles for a Tier III facility; and
  - Provides for redundancy in computing, communications, cooling and power.

- Emergency Preparedness risk considerations were factored into site selection and facility design, mitigating the current risk the BUCC is exposed to (i.e., not in a flight path, transformer station, etc.).

Risk Mitigation:

- Construction commencement is contingent on the required OEB approvals and if not planned accordingly, could pose project schedule risk. This has been mitigated through a schedule adjustment that will initiate commencement in alignment with OEB schedules.
- Municipal Approvals impose risk to the project schedule however during the current detailed design stage, the municipality has been consulted throughout the process mitigating the risk of future change requests or delay for approvals.
- Site development and environmental risk due to discovery of adverse subsoil conditions. This risk has been mitigated through several borehole assessments of subgrade soil conditions to determine: (a) foreign objects; (b) soil contaminants; and (c) suitability of soil cohesion for adequate foundation strength and no notable issues have been discovered.
- Construction risk due to change requests, lack of performance of proponent and increased costs have been mitigated through plans for Hydro One's and the external designer monitoring on site activities throughout construction ensuring issues are discovered and addressed early and that required contract quality is delivered to schedule.
- Alignment of dependent sub-projects has been identified as a potential risk as a delay in delivery of communication path connectivity to the control network would delay future in-service and commissioning activities. This risk is mitigated through early commencement of this activity to ensure adequate lead times.
- Factors affecting implementation timing and priority are those identified in the Investment need section which speak to the increased reliability risk for backup Operations. These factors have been reviewed and the priority has been set to "high" given the high cost for remedial efforts and the impacts on Operations and Hydro One customers if further failures are experienced.

Result:

The integrated strategy behind the ISOC facility maximizes investment utilization as well as value generated by eliminating the need for additional sites and facilities that would otherwise be required. By building one centralized site to house all stakeholders, economies of scale synergies will be realized. These come in the form of negating the need for multiple designs, development, sites, facilities (buildings), critical support infrastructure, future maintenance maximizing capital investment, limiting overall rate impacts.

All proposed tenants require critical support infrastructure to meet an availability target commensurate with the criticality of the systems and functions they support (99.95%). The requirements are prescribed by Hydro One internal reliability standards and guided by industry best practices (Uptime Institute Availability "Tier" levels). Critical support infrastructure and IT investment to achieve this objective represent significant investment. With the current ISOC strategy, critical support infrastructure is shared and represents incremental cost to achieve rather than replicating with several installations that would be required to support several sites across Ontario.

- Enhanced monitoring, control and coordinated Customer response (Operating, ITMC, Security and Emergency Preparedness);
- Examples include;
  - Coordinated response for all system vulnerabilities i.e. system events, telecommunication events, cyber events or physical threats through integrated communication within the ISOC facility.
  - Enables future dual active sites, removing activation timelines of backup Operations.
- Share enhanced building protection design and security (physical facility hardening to protect against severe weather or man made threats);
- Share redundant backup generator power supply and other emergency supplies;
- Enhanced site location for improved activation response, elimination of NOD's interim BUCC, adherence to emergency preparedness criteria, dual purpose use for training (negating need for additional training facilities) and other business operations; and
- Enhanced security with centralized operations, improved monitoring and analysis trending for proactive response, and situational awareness for coordinated resolution. An Emergency Operations Centre for Business Continuity and Emergency Preparedness will also be provisioned as part of the Security Operations Centre.

Outcome Summary:

Customer Focus	• Improve the reliability and availability of emergency activation, response and restoration in the event any failure is experienced in the Primary Control Centres. • Reduced rate impacts from a single integrated solution as compared to multiple standalone investments. • Retiring of the current interim NOD BUCC and removal of the risk of costly remedial efforts in the event further failures are experienced.
Operational Effectiveness	• Mitigates the critical risks (infrastructure failures, capacity constraints, location and activation timelines etc.) that exist at the Network Operating Backup Control Centre and the Backup Integrated Telecommunication Management Centre. • Monitoring and control reliability will be sustained under all system contingency scenarios improving Hydro One's compliance risk, customer responsiveness and Operational agility.
Public Policy Responsiveness	• Accommodate all regulatory requirements for physical protection, cyber security and activation timelines responsiveness. (See Appendix A and Compliance section of this document for further details).
Financial Performance	• Reduce the cost impact to Hydro One customers through the realization of economies of scale, mitigating the need to provide multiple sites, buildings and shared critical support infrastructure. • Negate the need to maintain an Interim NOD BUCC and reduce the risk of costly mitigation in the event additional failures are experienced at the main BUCC.

Costs:

Key considerations affecting the final cost of the project consist of the following:

- Availability and Reliability Standards including the need for redundancy in system and building architecture to maintain the existing target of 99.95%. The largest cost element revolves around the Data Center and critical support infrastructure, and the "Tier" or "Redundancy" level can weigh heavily on the investment required. Given the criticality of the Control Centre functions, with leading industry advice, a Tier III level was recommended and designed. This category includes the investment required in the SONET control telecommunications network required to connect the BUCC to field assets for monitoring and control.

- Security Requirements impose additional cost considerations ensuring the facility can withstand both natural and human events i.e. Tornado's, blast protections. Included in this consideration are prescribed regulatory requirements for six sided secure perimeters, cyber security (IT architecture), site access and monitoring of critical assets.
- Costs have been managed through an extensive and thorough assessment with various third party industry experts, internal subject matter experts as it relates to industry best practices, cost saving initiatives (i.e., free cooling), alternative option assessment for independent project elements (site selection, industry comparators), integration of solutions for various business units, functions and needs across Hydro One at a single site. An independent cost consultant has provided costing of the current stage of detail designs.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	10.5	42.6	3.3	-	-	56.4	64.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**10.5**	**42.6**	**3.3**	-	-	**56.4**	**64.4**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**10.5**	**42.6**	**3.3**	**0**	**0.0**	**56.4**	**64.4**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

APPENDIX A – DETAILED PROJECT DESCRIPTION

This investment, formerly known as the Backup Control Centre – New Facility Development, has expanded to include other operational synergistic lines of business that require facilities to perform similar functions (operating, monitoring, control and response functions) that are critical to support Network Operating and to secure Hydro One's assets. An integrated solution was sought to ensure costs are minimized, maximizing the effective utilization of critical infrastructure, office space and the site with the intent to maximize capital investments and reducing customer rate impacts. Below is a description of the Security Operations (SOC), Security Event Monitoring (SEM) and the Integrated Telecommunications Management Centre (ITMC) identified investment need.

The Backup Integrated Telecommunications Management Centre (BUITMC), in-serviced in 1950, requires extensive setup during activation and cannot accommodate back office support staff and regulatory security requirements for access control for critical computing equipment. The current HVAC is not adequate for net new occupancy or equipment and lacks the necessary facilities should a prolonged activation be required. ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure. In the event the ITMC cannot meet its service objectives, and Hydro One experiences an issue with telecommunications paths, Network Operating will be unable to monitor or control the respective field assets. ITMC requires a new Backup Control Centre to alleviate the risk at the current location.

Security Event Monitoring (SEM) is accountable to provide cyber surveillance monitoring services and requires Data Centre capacity, (not a physical tenant) to support primary and backup operations. SEM monitors Network Operating's Compute Network to ensure threats are detected, assessed and remediated so that critical cyber assets are not negatively impacted. Loss of visibility, control or erroneous operations of equipment due to a cyber-vulnerability, poses a serious threat to Hydro One's Operating functions. The risk of cyber related events has increased rapidly due to the relative increase in the amount of IT critical cyber assets employed in Hydro One Networks.

A Security Operations Centre (SOC) and an Emergency Operating Centre are required to provide a primary site for operations, monitoring and coordinated response for physical security threats and are imperative for business continuity. Currently, Security Operations are dispersed across the province and is reliant on third party services. In the event the current vendor cannot meet service obligations, Hydro One will be unable to monitor its critical sites. An integrated security presence at the ISOC will ensure physical threats can be detected, assessed and appropriate response dispatched. If a physical threat goes undetected, catastrophic impacts can result, in the event critical assets are damaged, which has potential to result in sever impacts to the Transmission and Distribution system networks. In addition, a lack of detection has potential to expose Hydro One to safety and environment risk for staff and the general public.

The current ISOC investment has evolved through a significant collaborative effort with Hydro One Network Operating, ITMC, SEM, Security Operations, industry participants and external subject matter experts. Initiation of this investment was predicated on current asset driven deficiencies / requirements (documented safety hazards, capability constraints, Reliability/Performance Impacts and risks, failures, condition, age, obsolescence, and regulatory and/or Hydro One standards (as described above).

Below is a detailed description of the ISOC investment planning process and execution strategy, which has been developed with the aim to a) fully understand requirements and needs across Hydro One; b) gather leading industry best practices, lessons learned; c) develop detailed programmed space and sizing requirement and asses against industry benchmarks; d) project costing from leading industry experts; e) ensures cost controls and oversight.

Planning Needs Assessment: Phase One

Requests for Proposals (RFP) were issued to conduct a Market scan and a Planning Needs assessment. This provided a detailed assessment of sites available in the market that met a set of specific "essential location requirements" and to provide expertise into the conceptualization and documentation of business needs and requirements of Hydro One Networks, ITMC, SEM and Security operations. The main focus was balancing needs and costs against reliability requirements, industry best practices (including Industry participant's feedback (New York ISO, New England ISO)) and lastly with lessons learned from the current Primary Ontario Grid Control Centre (OGCC). In addition, business requirements were translated into programmed space requirements based on Hydro One's experience and at the advice of industry experts. A basis of design was developed, capturing the stated requirements and a cost estimate was provided by an external estimator (for building and support infrastructure) and internal Hydro One engineering groups (for Telecommunications and Dual Power and Power System IT).The final basis of design and cost estimate were utilized to initiate the subsequent Detailed Design Phase.

The sizing of the ISOC is predicated on duplicating the OGCC current functions for Backup Control, including parallel use for training simulation and controller / dispatcher training.

The training facilities at the OGCC are currently at capacity. This effectively reduced the size of the ISOC facility by negating the need to program space for training simulation and instead uses technology to use real-time operating space while not active (in backup mode). In the event the OGCC is rendered inoperable or uninhabitable, the new ISOC facility will be able to continue all day to day functions indefinitely with a limited transition period, expected to be one hour or less.

Security Operations sizing was predicated on defined needs of operators, support staff, an investigation room and an Emergency Operations Centre (which will utilize a shared conference rooms when required).

ITMCs Backup Control Centre duplicated the current Primary Centre exclusively, including Control Room space, Data Centre requirements and provisions a back office support compliment to ensure adequate facilities are available for prolonged activation redundancy and assurance of Operations.

SEMs compute needs were documented, forecasted and the incremental capacity was added to the Data Centre white tile space.

Future growth has been accommodated and captured in the detail design however not all space will be built in the initial ISOC build. Data Centre growth has been included up to and including 2035 due to the sensitivity of the equipment and the risk future construction would pose; however the support infrastructure will be purchased on an as needed basis. Future facility expansion will be enabled for future consideration by way of footings and ensuring construction can be achieved without impacting operations (designing connection points etc.) Future extension of the facility, when required will be included in future OEB rate cases.

Detailed Design: Phase Two

At the completion of the Planning Needs Assessment Phase, a Detailed Design phase commenced with the objective to provide all required documentation, designs and costing to tender the end state solution for construction. During this phase, all drawings, facility programing (space definition), IT architecture etc. will be completed, including site procurement (~$3M), Proof of Concept for IT architecture and a final estimation. This information will be packaged and ready for submission for RFP for the construction phase. It is expected to be completed in 2017.

Pending completion of the Detailed Engineering Design and receipt of required approvals, Hydro one will leverage its internal Supply Chain, an Open Market Construction Tender process in two phases.

Phase One: Request for Pre-Qualification ('RFPQ")

Hydro One will seek to pre-qualify a select number of vendors in an open market process, who demonstrate "required competencies" (e.g., proven large project construction experience, defined safety/environmental programs, change control process controls, demonstrated ability to deliver large construction projects on time and to budget, etc.) related to the construction of the ISOC and acceptance of HONI required market-based Terms and Conditions.

Phase Two: Request for Proposal ("RFP")

Hydro One will release to only the pre-qualified vendors a detailed RFP with a complete set of construction documents. Pre-qualified vendors will be required to review the construction documents, offer input with respect to area's which could result in increased costs if not addressed before construction and provide a "fixed" price proposal to a defined scope of work and schedule, linked to a delivery penalty.

Construction Phase: Phase Three

The successful proponent will commence construction and is planned for Q4 2017.

Post Construction award: Hydro One's external designer will monitor on site activities throughout the construction to ensure any issues are addressed early and that required contract quality is delivered. HONI and designates will participate in interactive Bi-weekly onsite construction process meetings to gauge progress to requirements and address concerns which may impact the process.

The ISOC investment has been identified and assessed as a high priority and was subsequently prioritized and planned due to risk and considerations described below.

Site location risks that will continue to be present as there are no viable remedial alternative to the following risks:

- The current site location, and required travel time, requires maintaining an interim backup facility to perform limited functions in the event the OGCC is rendered inoperable and staff have to transition to the BUCC. The ISOC will eliminate this requirement;

- Structure is landlocked, and no expansion potential exists as the facility is surrounded by a Transformer Station;
- Current emergency preparedness risks will remain:
    - In a flight paths (Pearson International Airport);
    - Between two major highways (Hwy 427 & Hwy 401) in the event of hazardous spills;
    - Gas pipe lines located underneath property;
    - Adjacent to transformer station (electrical, fire and asset failure hazard). In 2011, T7 and T8 transformers at Richview both failed catastrophically, resulting in loss of the station and a major fire. This removed the BUCC from use for an extended period of time;
    - Congested area in the event of wide spread emergencies i.e. Civil unrest, blackout, natural disaster, and commute;
    - Adjacent to public storage facilities.
- Facility risks that could render the Hydro One Networks Control Centre or critical equipment unavailable for an extended period of time, eliminating redundancy of critical monitoring and control of the Distribution system include:
    - Flooding in basement, roof and cable entrances, where computer rooms, power rooms, telecom rooms, switchgear, and SONET communications are currently located;
    - Failures of critical support infrastructure including; the fire panel, HVAC, emergency backup power (generator);
    - Inability for expansion and a high cost for retrofit / maintenance activities;
    - Relocation of the equipment located in the basement of the facility is not viable given the space required on the main floor (Computer rooms, telecommunication gear (SONET), Uninterrupted Power Supply units, switchgear etc.;
    - Competing demands for physical space, power, cooling from multiple tenants; and
    - Electric power system is undersized (Station Service).
- ITMC's current BUITMC has documented the following risk and constraints;
    - Located in a shared space with an inability to expand;
    - Requires extensive setup during activation as the facility cannot accommodate a permanent active installation;
    - Cannot accommodate current back office support requirements;
    - Cannot meet security requirements for access control for critical computing equipment;
    - The current HVAC is not adequate for net new occupancy or equipment;

- Lacks the necessary facilities should a prolonged activation be required; and
- ITMC is a critical element in ensuring that the Network Operations telecommunications network is available and in providing first level support in the event of any communications failure.

Hydro One's Security Operations are currently reliant on an external facility that is owned and operated by a third-party creating corporate and regulatory risks given that Hydro One lacks a contingency site that is capable of monitoring the physical security of its sites and assets. Should the facility or 3rd party services no longer be available to Hydro One due to factors outside of Hydro One's control, Hydro One will not be in a position to monitor the real-time security (including door alarms, motion sensors etc.) of its critical sites, creating both a security and public and employee safety risk. Such an occurrence would also lead to a regulatory non-compliance violation with NERC Standards and possible sanctions, financial penalties and risk to corporate reputation.

1 **APPENDIX B – DETAILED ALTERNATIVE COMPARISON**

2 Detailed Alternative Comparison

Alternative	Description	Cost ($)	Size (Sq.Ft)	Site (Acres)	Cost / Sq.Ft	OM&A**	Benefits / Risks
Alternative One: Status Quo	Maintain existing facilities. (BUCC remediation activities, lease new data hall space and for BUITMC Requirements).	$78M*	18,921	N/A	N/A	N/A	No provision for SOC. BUCC existing location, space, and site constraint risk remains. Significant difficulties for prolonged activation. Includes a leased space for BUITMC, leased Data Centre space for NOD and remedial work to retrofit office space to better accommodate prolonged activation.
Alternative Two	Build NOD BUCC and Data Centre.	$104.8M*	95,420	10+	$1,098	$3.72M	Site, SONET, Dual Power and critical support infrastructure included.
Alternative Three	Build ISOC as BUCC, BUITMC with back office and Data Centre.	$124.7M*	99,716	16.41	$1,251	$4.0M	This includes the preferred site and all critical support infrastructures including but not limited to: SONET, Dual Power, redundant generation, UPS, cooling, shared office and common space. This excludes SOC from inclusion.

Alternative	Description	Cost ($)	Size (Sq.Ft)	Site (Acres)	Cost / Sq.Ft	OM&A**	Benefits / Risks
Alternative Four	Acquire an existing facility for BUCC and BUITMC and integrated Data Centre	Not available. Building specific market scan by Andrew Thompson and Associates (ATA) indicated no suitable site for consideration at time of assessment. Hydro One owned sites were reviewed internally; however also found that no suitable site or facility existed.					
Alternative Five	Build Primary NOD Control Centre, primary SOC, and BUITMC.	$141.9M*	146,200	16.41	$971	$4.47M	This option assumes that the existing OGCC staff would be moved to the new ISOC and the current OGCC used a Backup. Additional compute / system investment required which is not included in total cost.
Alternative Six	Initiate Build of ISOC with future dual operating capabilities.	$130.0M*	126,200	16.41	$1,030	$4.47M	Provides a NOD BUCC, BUITMC, and Primary SOC including shared integrated Data Centre, and back office support. Current lifecycles for critical applications respected, alleviating addition IT requirements to enable Primary operability. Dual Primary enabled for future implementation.
Ontario Grid Control Centre (data for comparison purposes)		$144.9M	68,000	9.25	$2,131	N/A	Presented in 2016 dollars (originally $118M investment in 2003) Provided for comparison.
*The Distribution portion of this total is 50.07% of the total cost. **The OM&A cost estimates are the full total cost, and these have not been adjusted to show the distribution portion only.							

Data Centre Construction vs. Leased Data Centre

In addition to the above alternatives, a comparison between the option of construction versus a comparable colocation or leased data centre option was conducted by engineering firm Morrison Hershfield, to ensure the most cost effective means of providing needed Data Centre space. This is the largest cost consideration in the overall project total. This assessment was based on a 15 year term based on market prices in the Toronto area. The Toronto area was utilized for this study as it provided a much larger pool of lease options with the required reliability / Tier level standards. The results are shown below which indicated that the co-location/lease option ($122.1M), based on the current design criteria, far exceed the cost of the build option ($73.2M) ($30M in Capital + Incremental annual OMA at $2.5M escalated at 2% per year for 15 years, $43.2M).

	IT/POWER MRC*	**Annual Cost of Rent**
Year 1	$ 341,144.00	$ 4,093,728.00
Year 2	$ 372,529.25	$ 4,470,350.98
Year 3	$ 406,801.94	$ 4,881,623.27
Year 4	$ 444,227.72	$ 5,330,732.61
Year 5	$ 529,725.56	$ 6,356,706.73
Year 6	$ 529,725.56	$ 6,356,706.73
Year 7	$ 578,460.31	$ 6,941,523.75
Year 8	$ 631,678.66	$ 7,580,143.93
Year 9	$ 689,793.10	$ 8,277,517.17
Year 10	$ 753,254.06	$ 9,039,048.75
Year 11	$ 822,553.44	$ 9,870,641.24
Year 12	$ 898,228.35	$ 10,778,740.23
Year 13	$ 980,865.36	$ 11,770,384.33
Year 14	$ 1,071,104.97	$ 12,853,259.69
Year 15	$ 1,169,646.63	$ 14,035,759.58
	Total 15 Year Spend	$122,101,320.25
*MRC = Monthly Recurring Charges include IT load rent, estimated power charges and PUE of 1.6		

Other factors that affected this consideration are; a) no co-location facility provides NERC certified space which would require additional upfront capital cost in year one, b) many facilities have policies that dictate access, upgrade, expansion and security for the facility without renter input which exposed Hydro Ones critical equipment to further risks.

ISOC Breakdown	Est. Cost	Ft2	$ / ft^2	Report Findings of Morrison Hershfield on Build Comparisons
Building Shell Cost	$23M	120,534	$250	Includes shell and basic Mechanical Electrical Power services. This is considered at the bottom of the range of $250/ft2 -$1000/ft2 for hardened facilities of this type, which equals the cost per square foot for SaskPower's most recent facility design. Variance consisted of EF3 Tornado rate vs. EF4 for SaskPower with less office space and did not have Control Room space. Average generic office space range from $150 - 250/sq. ft. dependent on finish and furnishings.
Data Centre Cost	$30M	11,990*	$2502	SaskPower's estimates cost per sq. ft. for data centre space was $3,000 / sq. ft. and it is MH's conclusion that $2502 is within range of similar facilities. A similar telecom project in 2015 with a similar Tier level as HONI was $2575/sq.f.t.
ISOC Total	$130M**	127,703	$1018	This includes Building Shell, Outdoor Yard and Data Centre.

- **Included support galleries (cooling, power distribution).*
- ***Note: The Distribution portion of this total is 50.07% of the total cost.*

<u>Comparisons to Similar Facilities at Other Utilities</u>

Lastly, NOD reviewed a number of utilities investments in facilities and data centre development projects to ascertain the reasonableness of the ISOC scope as compared to the rest of the industry. Below is a table summarizing these findings; which show the ISOC is in line with the cost per square foot for comparable projects.

1

Industry Comparators	**Description/Name**	**Cost ($M)**	**Size (Sq. ft.)**	**Year Built**	**Adj. Cost to 2016 $ (CPI)**	**Cost (2016 $) / Sq. ft.**
New York Independent System Operator	NYISO Control Center	$59.4M	64,000	2014	$60.82M	$950
American Electric Power	Transmission Operations center	$57.2M	83,500	2007	$65.92M	$789
ISO-New England	Windsor Backup Control Centre	$50.7M	70,000	2014	$51.91M	$742
Pacific Gas & Electric	Distribution Control Center	$52.0M	37,674	2015	$52.57M	$1,395
	Distribution Control Center	$37.05M	24,000	2014	$37.97M	$1,582
	Distribution Control Center	$46.8M	50,000	2016	$46.8M	$936
First Energy	FirstEnergy Tx Control Centre	$58.5M	70,000	2013	$61.16M	$874
BC Transmission Corporation	System Control Modernization Project	$133M	113,022	2008	$148.07M	$1,310
	System Control Centre (building ONLY)	$40M	64,584	2008	$44.53M	$689
	Backup Control Centre (building ONLY)	$30M	48,438	2008	$33.4M	$690
Average Cost :				-	$60.3M	$996
Distribution Portion of ISOC.		$64.4M	63,851.5	2016	$64.4M	$1,009
Proposed ISOC Cost Comparison		$130M	127,703	2016	$130M	$1018

2 *Converted from USD to CDN at an exchange of 1 USD to 1.3CDN*
3 *Note: The ISOC is comprised of Distribution, Transmission, ITMC and SOC.*

Site Assessment

As the table below shows, sites south of Barrie were higher cost and the sites North of Barrie were considerably less expensive. Orillia, given its relative location compared to the Primary Centre, was optimal given the City size, access, lodging, development and emergency services, including the OPP headquarters. Communities further away were ranked lower due to distance, access to emergency services, development and lodging, winter driving hazards and relative site suitability among other factors.

Ranking	Community	# of Sites	Ave. Cost / Acre
1	City of Orillia	4	$114,935 - $181,200
2	Town of Bradford	3	$346,636
3	Town of Collingwood	3	$135,469
4	Town of Midland	6	$90,000
4	Town of Penetanguishene	3	$87,500
5	Town of Alliston (New Tecumseth)	3	$273,900
6	Town of Newmarket	2	$850,000
7	Town of Orangeville	1	$215,000
8	East Gwilliambury	6	$400,000
9	Angus	1	$80,000
10	Innisfill	0	$ -
11	Schomberg (King Township)	1	$475,000
12	Wasaga	0	$ -

Note: An assessment of internal Hydro One TS sites was reviewed against available acreage and emergency preparedness criteria and was determine that there was no existing Hydro One site that could accommodate the proposed facility. This represented a departure for previous assumptions with impacts of land purchase and support infrastructure that must be extended to the preferred site.

GP-19 Operating - Common Information Technology Infrastructure

Start Date:	Q1 2017	**Priority:**	High
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	11.0
Primary Trigger:	Asset Driven		
Secondary Trigger:	Reliability/Performance		

Investment Need:

The Common IT ("Information Technology") infrastructure is the shared IT backbone of Network Operating's critical enterprise systems. It is technically more efficient and maintains a lower total cost of ownership as compared to multiple discrete instances to support specific systems. This translates into less sustainment and total system component purchases. Common IT infrastructure is further defined into sub categories, which include:

- Data storage (devices that retain, retrieve and archive digital computer data "information");
- Compute servers (processors that fetch, decode, execute and write data in response to system processes and application inquiries);
- Computer consoles (microcomputers used by Operating Dispatchers, Operators and Managers to interface with applications);
- Information Technology networks (a series of communication paths interconnecting IT devices); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS.

Each sub category includes hundreds of individual assets, both hardware and software products. IT products have lifecycles for a number of reasons, for example market performance, and technology innovation and development, drive change in products or the product matures and is replaced by functionally richer technology. As new technologies are developed, support and the ability to purchase spares or replacements equivalent to in-serviced assets is more costly and difficult to achieve. Regardless of the reason for change, supporting products beyond their lifecycle poses increased risk to Operations.

If extended support agreements are made available, the costs are typically a minimum of two to three times that of current supported market products, which drives consumption to the latest offering. Furthermore, product replacement parts become scarce and inflated in price and run the risk of non-compatibility with other more current devices. These factors and others make the employment of products beyond their lifecycles untenable. As each device is interdependent and the future replacement technology attributes are almost always unknown, pacing and prioritizing is an ongoing effort. Vendors often announce lifecycle support conclusion dates with minimal notice. The continuous process of assessing device compatibility at its lifecycle conclusion requires careful architectural consideration to ensure system reliability and performance standards are constantly being met.

This investment is comprised of multiple asset groupings, and is required to maintain the viability of the common IT infrastructure for Operating's computer applications such as the Outage Response Management System, Network Outage Management System, Network Management System, and Distribution Management System. (Discrete application infrastructure is not included in this investment). These applications are leveraged by both Distribution and Transmission. However this investment represents the Distribution portion exclusively.

Alternative 1: Status Quo:

This alternative is to maintain status quo: do nothing and continue to use the existing IT infrastructure. As each device represents an important interconnected component of the common infrastructure, not proceeding with these lifecycle replacements could result in the following:

- Hydro One's diminished capacity to serve and respond to customers;
- Regulatory non-compliance with the potential for heavy fines;
- Potential loss of one or more mission critical applications;
- Significant increase in Operating maintenance costs;
- Loss of the original equipment manufacturer/vendor support;
- Increased probability of system failures;
- Inability to recover from system failures;
- Increased vulnerability of cyber terrorist attacks;
- Potential to strand future application upgrades and enhancements; and
- Risk of costly remedial efforts in the event of a failure.

Alternative 2: Maintain Supported IT Infrastructure (Recommended):

Lifecycle management based on industry best practices and vendor support schedules ensures the viable operation of Operating IT infrastructure assets, including the enablement and continued reliability of critical application systems. The dynamic architectural model requires Operating to plan and replace devices with the appropriate current technology and is recommended as the only viable option. This option offers the following benefits:

- Continued compliance with availability and reliability standards;
- Current market product maintenance and support costs;
- Original Equipment Manufacturer ("OEM")/vendor provided updates and software patches;
- OEM/vendor available replacement parts at current market prices;
- System compatible infrastructure devices; and
- Improved ability to recover from random failures.

Through systematic replacement of common IT infrastructure Hydro One Networks can sustain business functions by ensuring the tools and systems used to support Operations are functioning as designed, are fully supported, and ensure any failure can be readily remediated. This provides the assurance to Hydro One customers that IT failures will be minimized and if a failure is experienced it will be returned to service in a timely fashion. This approach maintains Hydro One's commitment to customer satisfaction by ensuring responsiveness through system availability.

Investment Description:

These IT infrastructure investments include the following asset sub categories and are located at both the Ontario Grid Control Centre ("OGCC") and the Back-up Control Centre ("BUCC"). Servers, PCs and disc drive counts are always fluctuating depending on the current state of lifecycle management projects. Lifecycles of the various components are dynamic, and can at times be interdependent, influencing other components. The hardware is generally problem-free, however lifecycle management means keeping it in a supportable state as dictated by the vendor. Disc drives do fail but are replaced under service agreements. All devices would be current to the year they were "lifecycled" and there isn't a single "project" that replaces everything at once in a single year therefore the age distribution will always vary. Lifecycle planning forecasts in each category has leveraged historical trends, however careful consideration regarding the lifecycle replacement and transferability of the infrastructure will be provided as Operating relocates the BUCC into the Integrated System Operations Center beyond 2020 including:

- Data Storage (i.e., storage area network devices "SAN"; achieve data storage backups);
- Compute Servers (i.e., secure file transfer devices; monitoring systems; server operating systems);
- Computer Consoles (i.e., Windows operating systems; peripheral devices);
- IT Networks (i.e., remote access devices; satellite time clocks); and
- Operating Systems/Applications/Software (i.e., VMware, a virtualization of servers/desktops), Citrix (presentation software), Windows Server and Desktop OS. Oracle and SQL database applications.

A failure of a single component has the potential to cause cascading impacts including; a failure of a critical application and the business function it supports, removal of system redundancy, or worst case, render the OGCC and/or computer systems unavailable. The resulting impact on work execution and customers could be as follows:

- Cancellation or delay of outages requiring planned field work causing customer or Hydro One work to be delayed, requiring rescheduling, reprioritization and rework;
- Unresponsive distribution outage management and lack of communication with customers and staff posing work delays, safety risks and inability to respond to emergency events (i.e. if failure occurs during Storm event); and
- Backup activation which limits full business function and hinders critical response.

Risk Mitigation:

Replacing end of life infrastructure assets is recommended as "best practice" in order to maintain Network Operating's current supported, compatible and redundant IT infrastructure and equipment. The ongoing dynamic processes to cost effectively assess, prioritize and stage each product in its respective category must remain in focus by Hydro One's Power System IT architecture team and supporting management and staff at all times in order to achieve success now and in the future. The driving focus behind these processes is to maintain current reliability and service levels with the continued support of mission critical applications and their function is to serve Hydro One's customers in the most cost effective manner possible.

Result:

These investments will provide cost conscious ongoing product support and dynamic lifecycle management for all common Operating IT infrastructure assets.

Outcome Summary:

Customer Focus	• Provides continued support to key customer applications such as the Outage Management System supporting emergency storm response, communication, and outage coordination. • Minimizes customer risk and associated impacts of outages of the system.
Operational Effectiveness	• Provides Operating IT infrastructure the required facilities to holistically support mission critical Operations applications, systems and their functions. • Decreases risk of reduced performance, or an inability to meet service levels in the event of a failure.
Public Policy Responsiveness	• Ensures mission critical Operations applications and systems are supported with the current, compatible and supported IT infrastructure to maintain reliability and availability targets and meet regulatory requirements with regards to cyber security, reliability (redundancy), etc.
Financial Performance	• Provides cost effective management of IT lifecycles with current and supported common "shared" IT infrastructure. • Reduce OM&A and negate the need for costly extended support. • Improved asset performance, and greater ability to recover from a failure. A single failure can impose significant costs from the disruption to business function, increased labour cost for emergency break fix needs and other remedial efforts.

Costs:

This group of investments is estimated based on historical cost, subject matter and industry experts input, assessments and will be adjusted for the project scope, local condition and market pricing at the time of the investment.

Controllable cost have been minimized through the continued use and shared costs of common platforms, maximizing space, storage, and networking; maintaining current versions / latest technologies to maintain or reduce OM&A costs; and bundling of work to minimize outages or impacts to Network Operating.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.7	1.4	0.8	2.1	4.1	11.0
Operations, Maintenance & Administration Removals	-	-				-
Gross Investment Cost	**2.7**	**1.4**	**0.8**	**2.1**	**4.1**	**11.0**
Less Capital Contributions	-	-				-
Net Investment Cost	**2.7**	**1.4**	**0.8**	**2.1**	**4.1**	**11.0**

**Includes Overhead at current rates.*

GP-20 Network Outage Management System (NOMS) Refresh

Start Date:	Q1 2016	Priority:	High
In-Service Date:	Q2 2018	Plan Period Cost ($M):	1.1
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Reliability -Regulatory		

Investment Need:

The Network Operating Divisions ("NOD") Network Outage Management System ("NOMS") is Hydro One's primary outage planning tool. The associated hardware and software is specific to NOMS and does not include any shared storage in the Common Information Technology infrastructure. As required by the Ontario Energy Board ("OEB") Distribution System Code ("DSC") and Hydro One's Conditions of Service, NOMS provides essential coordination and scheduling of planned outages through integration with enterprise systems and the internal lines of business for reduced customer impact, optimized outage performance and improved communication amongst stakeholders (i.e., Local Distribution Companies, Large Distribution and Transmission customers, Hydro One work groups).

NOMS is an essential tool for planning, scheduling, assessing and executing distribution equipment outages. The viability of the tool is being reviewed and investigated for potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors being considered are availability, sustainment cost, system growth, the availability of new technologies, and compatibility with other critical Operations systems and applications, such as the Equinox Control Room Operations Window ("CROW"), Utility Work Protection Code, Electronic Log, and SAP applications. The system must be supported by the vendor or Original Equipment Manufacturer (OEM) as the risk of system downtime directly affects distribution operations and Hydro One customers.

The investment in a new NOMS tool must also satisfy regulatory requirements such as the OEB DSC Section 4, Operations; specifically Section 4.4.7 which requires a utility to provide as much advance notice as possible for the duration and frequency of a planned outage. This outage tool must also ensure compliance with Hydro One's Conditions of Service policy, Section H, Outage Notifications Process with customers.

The current version of NOMS was placed in service in 2010 after an application software upgrade to version 2.0 (NOMS V2). The software upgrade did not include a hardware upgrade at that time. The NOMS system consists of application servers, primary database servers, reporting database servers and a backup disaster recovery database server. An investment is now needed to upgrade the NOMS application and hardware to address four inadequacies of the current system that pose operational risks to Hydro One:

- Vendor support has expired and extended support is no longer available on servers running Oracle's 10g software;
- Application and Database servers have reached end of life; and
- The Windows 2003 Operating System used for the NOMS application server is no longer supported and update patches are no longer available.

The results of these operational risks of running an unsupported application will only increase Hydro One's inability to recover outage planning systems in the event of a system failure. The impacts to Hydro One's business in the event of these failures would be loss of outage planning and coordination abilities, higher maintenance costs, failure to efficiently communicate outage planning efforts with stakeholders, and decreased safety for Hydro One employees.

Alternative 1: Status Quo:

The Status Quo alternative would maintain the existing NOMS unsupported software and end of life hardware. This alternative has been rejected for the following reasons:

- Continuing operations with end of life system hardware will increase the likelihood of a NOMS failure;
- Continuing operations on end of life hardware without vendor support will hinder Operations ability to recover systems in the event of a failure;
- Maintaining end of life hardware results in increased maintenance costs and workarounds; and
- The risk of increased frequency and duration of customer outages and reduced distribution system performance.

The risk and impact in the event of a failure of NOMS will be significant given the primary function of NOMS is to plan and coordinate all Hydro One work execution activities. This will have a significant effect on the operation of the Hydro One distribution system and its customers.

Alternative 2: Upgrade NOMS *(*Recommended*)*

This alternative would upgrade both hardware and software for the current NOMS application and address the unsupported software and the operational risks currently faced by Hydro One.

A new application, upgraded servers and operating systems will provide Hydro One with improved outage planning capabilities as part of the version upgrade and the ability to recover systems in the event of a failure that would otherwise not be possible with the Status Quo option. A reliable outage planning tool is a requirement of the OEB's Distribution System Code and Hydro One's Conditions of Service. It is prudent that a full NOMS upgrade is performed to maintain Hydro One's outage and work planning capabilities and to ensure the distribution system reliability and availability.

Investment Description:

Planned investments include a hardware refresh, operating system upgrade and the integration with other enterprise systems such as the Electronic Log, Utility Work Protection Code, SAP and the Outage Grouping and Assessment System Tool. These are either a part of the version upgrade or existing stand-alone systems that when integrated will enhance the flow and assimilation of information that will enhance the outage planning and reporting processes.

Risk Mitigation:

IT Infrastructure investments are complex and dependent on multiple technology factors including: application software, server capacity, physical constraints (i.e., cooling capacities), hardware compatibility and vendor support terms. Given these complexities, a development phase is being conducted as a part of the full NOMS upgrade to more effectively determine project costs and manage the risks and requirements associated with the project implementation. Additionally, an assessment of the enterprise systems; Electronic Log, Utility Work Protection Code, SAP, and the Outage Grouping tool will be performed to ensure value creation when merging the systems with NOMS.

Result:

This investment will result in the following accomplishments:

1. Increased stability of the NOMS system with upgraded hardware and software that has vendor support;
2. Reduced risk of a NOMS system failure;
3. Ensured regulatory compliance with the OEB Distribution System Code, IESO Market Rules and adherence to Hydro One's Conditions of Service;
4. Assessment and integration of internal and enterprise systems; and
5. Improved operational efficiencies and outage performance gained through the integration of enterprise systems and new technologies.

Outcome Summary:

Customer Focus	• Mitigate Customer impacts by providing as much advance notice as possible for the duration and frequency of a planned outage.
Operational Effectiveness	• Ensure reliability and availability of NOMS to ensure scheduling, coordinating and planning of Hydro One Distribution and Transmission System Outages. • Ensure operational efficiencies and process changes are fully leveraged by improving current workflow, coordination, grouping and execution of outage planning activities.
Public Policy Responsiveness	• Deliver outage management service obligations related to OEB Distribution System Code, Section 4, Operations, and IESO Market Rules part 7.3 Outage Management. • Maintain compliance with Hydro One's Conditions of Service.
Financial Performance	• Reduce extended support and maintenance costs associated with maintaining the system to mitigate failures.

Costs:

Costs are being controlled via an initial development phase, which will finalize scope, system architecture, and an execution strategy prior to full execution of this investment. In addition, several vendor products will be reviewed and assessed to determine which are the most cost effective and provide the most value. Lastly, through a full capital replacement, testing and commissioning activities will be completed simultaneously. This will negate the need for independent system component testing and allow the more efficient use of resources.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	1.1	-	-	-	-	1.1	2.2
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	1.1	-	-	-	-	1.1	2.2
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**1.1**	**-**	**-**	**-**	**-**	**1.1**	**2.2**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

Witness: Tom Irvine

GP-21 Data Centre Remediation

Start Date:	Q4 2016	Priority:	Demand
In-Service Date:	Q3 2020	Plan Period Cost ($M):	4.6
Primary Trigger:	Asset Driven – End of Life – Capacity		
Secondary Trigger:	Reliability -Regulatory		

Investment Need:

Hydro One maintains substantial Information Technology ("IT") infrastructure to operate, manage and control the Bulk Electric System ("BES") and Provincial Distribution Networks. These systems must operate in compliance with various regulatory bodies including North American Electric Reliability Corporation, Independent Electricity System Operator's market rules and Hydro One standards.

The Ontario Grid Control Centre (OGCC) Data Centre facilities can no longer accommodate the immediate and short term capacity requirements, given that the existing facility is beyond its space, power distribution and cooling thresholds.

The OGCC IT infrastructure is critical to the reliable operations of the Bulk Electric System and ensuring that NERC requirements are addressed in a timely and focus manner. The Power System IT (PSIT) department which (a part of the Hydro One Information Solutions Division (ISD)) focuses exclusively on the tools and IT equipment that are used by the OGCC to monitor and control the Bulk Electric System. An analysis by PSIT has determined that in order to maintain the following 24/7 Operating applications and systems over the next four years: Distribution Management System ("DMS"); Outage Response Management System ("ORMS"); Network Outage Management System ("NOMS"); Control Room Information System ("CRIS"); and Information Technology Service Management ("ITSM"), additional Data Centre capacity will be required.

These systems are used exclusively by Operating to monitor and control the distribution and transmission system asset in a 24/7 environment. They are physically separated from any other H1 network or domain. However, due to the aforementioned space, cooling and power distribution constraints at the OGCC and the BUCC, and given that ISOC (ISD –GP-18) will not be in service until 2020, PSIT has determined that remediation of the OGCC Data Centre is the most strategic option for the following reasons:

- A number of the major infrastructure at the OGCC is either approaching or has reach its end of life and will have to be replaced. These will include PDU, CRAC units and the Cooling tower;
- Remediation of the OGCC Data Centre addresses the current capacity constraints as it relates to space, power distribution and cooling; and
- Ensures that the OGCC Data Centre which will become the Backup Data Centre once ISOC is built is fully operational and can provide redundancy to meet the required NERC standards and maintain operational best practices.

Alternative 1: Status Quo

This option assumes Hydro One maintains the current over capacity state specific to the Ontario Grid Control Centre's computer room facilities and continues utilization beyond asset useful life. This is not considered a prudent approach due to the criticality of the systems that reside within the Data Centre and could result in the following:

- Increased risk from use of equipment and system components beyond end of life;
- Hydro One's diminished capacity to serve and respond to customers;
- Potential loss of one or more mission critical applications;
- Increased probability of system failures;
- Inability to recover quickly from system failures; and
- Risk of costly remedial efforts in the event of a failure.

Alternative 2: Remediate the OGCC Data Center *(Recommended)*

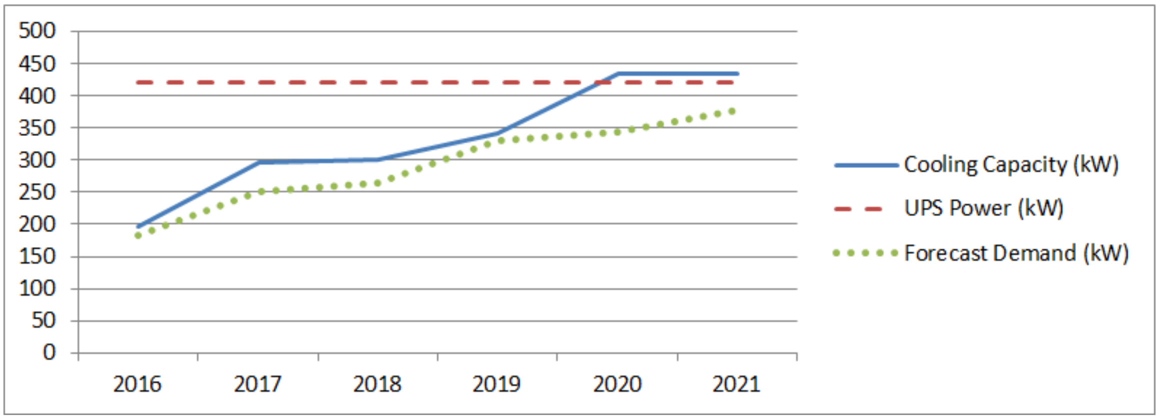
This alternative will remediate both computer rooms (A and B) located in the OGCC Data Centre in order to maintain system lifecycles and provide required capacity for system lifecycle management of critical operating systems and applications. This alternative remediates constraints and deficiencies to mitigate the increasing risk that the Data Centre environment and support infrastructure are posing on reliability of the system that reside within it. This will be accomplished by the following updates and changes such as:

- End of life replacements including increased capacity;
- Rack consolidation and defined infrastructure standardization;
- Decommission end-of-life powered IT infrastructure;
- Controlled air flow to enhance cooling efficiencies;

- Balance critical system loads over two Uninterrupted Power Supplies (UPSs) for redundancy; and
- Enhance Data Center protection, security monitoring and fire suppression.

The Data Centre's UPS power is reflected in the "dash line" at the top of the graph below. To utilize the 420kW of UPS power the project's activities will increase the cooling capacity (step function) from 197kW "solid line" and ultimately provide the Data Centre net capacity of 420kW. The "dotted line" represents the accommodated forecast demand over the project duration.

OGCC Data Centre – Cooling, Power and Demand (Computer Rooms A & B)



The remediation of the OGCC Data Centre to provide the needed facility capacities will support Operations functions over the next five years. This provides the assurance to Hydro One customers that Operations IT facilities are resilient with the capacity to facilitate mission critical applications and systems. This approach maintains Hydro One's commitment to customer responsiveness.

Investment Description:

This investment will provide an additional 223kW in Data Centre capacity through increased cooling and the redistribution of the available power based on the optimal physical space redesign of the computer rooms. This represents an increase from the Data Centre's current capacity of 197kW and provides the required Information Technology infrastructure into the foreseeable future.

This investment will ensure business continuity by maintaining the appropriate IT infrastructure to operate, manage and control the BES and Provincial Distribution

Networks. This is achieved via "mission critical" power system application lifecycle sustainment, maintaining continued vendor support, and without undue risk or threat of failure. This provides the assurance to Hydro One customers that IT failures will be minimized and if a failure is experienced, it will be returned to service in a timely fashion. As failures affect critical applications and tools, any failure can result in the OGCC being rendered unavailable for an extended period of time. A recent UPS failure and resulting equipment fire has shown that failures of support infrastructure have impacts on downstream elements. This investment approach maintains Hydro One's commitment to customer responsiveness by ensuring IT availability to maintain Network Operating key Operating and Dispatch functions. Below are the key activities of this investment:

- Reduce Data Center Load Risks:
  - Free Data Center floor space from rack consolidation activities and build new hosting standardization;
  - Reduce IT Infrastructure load to Power and Cooling by building new Pre-Prod and Prod environments at the Co-Location facility (ORMS, ITSM, NOMS, DMS); and
  - Decommission End of life powered IT infrastructure.
- Cooling:
  - Short term - Fix and control data center air flow to enhance cooling efficiencies;
  - Remediation of under floor cabling which is restricting airflow (utilized as the main plenum). This will include relocating cabling above the racks and improvements to the perforated tile system;
  - Define infrastructure standardization;
  - Expand cooling system infrastructure by using standalone (independent) cooling units with redundancy; and
  - Reduce the bottleneck demand on one type of cooling system inside Data Center.
- Power:
  - Build modern core power distribution;
  - Increase remote power distribution high-availability and flexibility at the rack level; and
  - Balance critical system loads over two Uninterrupted Power Supply (UPSs).
- Management and Remote Monitoring:
  - Implement remote management system and automated processes;
  - Enable proper monitoring system and automated reporting; and
  - Enhance data centre protection and security monitoring.
- Improved Fire Suppression and Monitoring:

- Build level one first protection system (Gas system);
  - Gas protection systems can extinguish quickly, minimize damages lowering repair costs and providing a speedy recovery time.

Risk Mitigation:

Increasing the available capacity of OGCC Data Centre facilities to facilitate applications and system lifecycles is recommended as “best practice”. The driving focus behind these facilities is to maintain current reliability and service levels and their function to serve Hydro One customers in the most cost effective means possible.

Ongoing work at the primary production Data Centre has potential to cause an unplanned system outage. This is mitigated by thorough failover automation and practices to the redundant production system located at the Back-Up Control Centre. In addition, co-location facilities will be leveraged to provide further redundancy and staging space.

In order to provide required interim capacity to enable this investment, a Co-location Data Centre facility will be leased during the remediation of the Ontario Grid Control Centre’s onsite Data Centre. This ensures the work at the existing Data Centre can be accommodated in off-peak cooling seasons (the winter months) without outages or a significant reduction in the redundancy requirements, and ensures that both current and planned system lifecycle upgrades are not stranded.

Result:

This investment will provide a cost conscious approach and ongoing IT infrastructure resiliency supporting dynamic lifecycle management for IT assets located at the OGCC Data Centre. More specifically it will achieve the following results:

- Maximized cooling efficiency in both Data Centre rooms:
  - Reduced load on chilled water cooling system;
  - New cooling units to support Data Centre demand and enhance redundancy; and
  - Eliminate the need to rent a mobile chiller unit during the summer months.
- Modern power distribution with enhanced monitoring and remote management system;
- Replacement of End Of Life (EOL) hardware infrastructure resulting in lower operating costs;

- Gain valuable data centre space for current planned investments and future growth; and
- Enhanced fire detection and suppression.

Outcome Summary:

Customer Focus	• Maintain Network Operating Customer service level agreements and meet reliability expectations. • Support customers by maintaining ability to provide storm or emergent response activities, communication outage coordination, dispatching functions, etc.
Operational Effectiveness	• Provide greater output capacity through optimization of support infrastructure and ensure adaptability to respond to business, regulatory or technological change. • Maximize available space, allow full utilization of existing assets and allow for future consolidation and standardization among IT racks, cabling, etc.
Public Policy Responsiveness	• Ensure that the primary Data Centre can maintain availability and reliability targets to a 99.95% target and maintain overall viability of the OGCC. • Maintains regulatory compliance to NERC, IESO Market Manual (Reliability of System Operations) and OEB Distribution & Transmission System codes.
Financial Performance	• Avoid costly new build or long-term rentals of a new facility for capacity offsite. This effectively negates further investment in net new equipment.

Costs:

The project will meet reliability / redundancy requirements by procuring interim short term co-location capacity to allow for Data Centre elements to be taken out of service while maintaining redundancy in critical applications. This will include a staged approach to ensure limited downtime / outages during execution.

A third party industry expert has reviewed the current requirements and has provisioned a detailed plan and cost estimate leveraging industry best practices, and market pricing with an aim to minimize ongoing maintenance (through Data Centre standardization and optimal configuration design).

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	2.4	1.6	0.6	-	-	4.6	10.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	2.4	1.6	0.6	-	-	4.6	10.0
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.4**	**1.6**	**0.6**	**-**	**-**	**4.6**	**10.0**

**Includes overhead at current rates. ** Total Project includes amounts spent prior to 2018.*

GP-22 OGCC Office Remediation

Start Date:	Q2 2020	Priority:	Medium
In-Service Date:	Q4 2022	Plan Period Cost ($M):	1.6
Primary Trigger:	Business Operations - Efficiency		
Secondary Trigger:	Health, Safety & Productivity		

Investment Need:

The Ontario Grid Control Centre ("OGCC") is Hydro One's primary facility that operates and controls the Distribution System. The facility is the headquarters for Network Operations and Hydro One's primary Control Room, and the Distribution Outage Management Centre among other supporting functions, essential in operations, monitoring and control of the Distribution System. The OGCC building has been in-service and operational, 24 hours a day, seven days a week, and 365 days a year since inception in 2003. Since this time, there has been minimal investment to maintain it as a productive office environment beyond normal break-fix remediation.

The OGCC building now accommodates more people and technology than was originally forecasted. The interior office space requires renovation to replace end of life fixtures, furnishings, floor coverings, walls, and other items. A thorough review of the security features (windows, doors, mantraps) is required to ensure efficient entry and egress, while respecting regulatory requirements including monitoring. The office furnishings including cubicles, cabinets and tables were in "used condition" when installed at the OGCC in 2003. The furnishings are end of life and will be over 20 years old when this investment is implemented in 2020. Life cycle assessments recommend that the useful life for carpeting and wall paint is roughly ten years for an office environment. The disrepair of floor coverings has created a safety concern for employees. As the OGCC houses the main control room with 24/7/365 operations, it must be brought up to current safety standards.

Alternative 1: Status Quo

This option assumes Hydro One maintains the current conditions at the Ontario Grid Control Centre. This approach poses risks to Hydro One employees and Hydro One's public image. This alternative has been rejected for the following reasons:

- Safety concerns including floor coverings are lifting and creating hazards;

- Amenities such as fixtures, carpeting, furnishings and wall paint are all well beyond their useful life and are showing signs of disrepair; and
- The diminishing office condition can affect employee engagement over time.

Alternative 2: Remediate OGCC Office *(Recommended)*

The recommended alternative for the OGCC Office Centre remediation is to proceed with the investment as a refurbishment of the current facility in line with the construction of the ISOC. The existing fixtures, carpeting, cubicles and paint have diminished below acceptable standards since it was established in 2003 and will be refreshed. Control Room consoles will be replaced and or retrofitted to include sit /stand functionality to improve ergonomics for staff and to reduce the risk for potential musculoskeletal injuries which will reduce lost time. A remediation of the facility is the least costly option and operationally disruptive due to the magnitude of the current investment in the OGCC and the business functions it supports. This option also allows scheduling flexibility to align with the construction of the new ISOC facility. This recommended investment will address the concerns of degrading working conditions and safety at the OGCC while delivering the most cost effective approach.

Investment Description:

This investment will involve Control Room renovations and office area/hallways refresh of the OGCC. Expenditures include replacing carpeting, repainting areas, enhancing lighting, upgrading conference rooms, and replacing furnishing to meet Hydro One Corporate standards, Ontario Building codes and Health and Safety objectives. This investment will review and implement security upgrades to replace the “PODS” (mantraps with dual authentication) in the front lobby as well as enhance security in the reception area to maintain six sided security in compliance with NERC standards.

Risk Mitigation:

Safety is the number one mandate at Hydro One and should be considered in this investment. As fixtures and carpeting age and deteriorate at the OGCC, lifted flooring has posed an increasing safety risk to the employees working in the facility. A remediation of the office facility will avert this safety risk and aligns with Objective OS3 of the Ontario Building Code which aims to minimize the probability that a person is exposed to an unacceptable risk of injury due to hazards caused by tripping.

A remediation to the OGCC facility is warranted. To mitigate the risk of cost escalation, the remediation is scheduled to occur in 2020 and 2021 to capitalize on the available space at the new Integrated System Operations Centre ("ISOC") facility allowing the temporary relocation of staff during construction. The ISOC is the closest and most cost effective site for the temporary relocation of Control Room employees. This will also eliminate the cost of a leased/rented third party office. Remedial efforts are currently hampered by the impacts that would result on the real-time operations environment. Alignment with the ISOC will ensure remediation efforts are not restricted by health and safety concerns (i.e. off gassing) and facilitates the completion of remediation work during regular hours for the support office areas, avoiding overtime costs. This investment timing offers the most strategic and cost effective approach to remediating the OGCC and will minimize the cost burden to rate payers. The current BUCC is limited by space and cannot support both the Control Room and the supporting offices currently working out of the OGCC and therefore is not an option.

Remediation will focus on furnishings that offer the best durability for economic value so that the expected life of the office remediation can be maximized. This will include leveraging office cubicles that maximize occupancy thresholds in the building. A proactive approach is more cost effective than a break fix strategy by mitigating costs for overtime, emergency material orders and a disruption to daily events in a real-time work environment.

Result:

Completion of the necessary improvements to OGCC office and control room space to gain efficiencies and mitigate the health and safety hazards associated with a deteriorating workplace infrastructure. The timing of the investment will provide a cost effective solution for providing an effective work location during the office remediation and a more productive work environment on completion.

Outcome Summary:

Customer Focus	• Ensure fulfillment of Hydro One's mandate to its customers by maintaining a healthy/safe working 24/7/365 working environment.
Operational Efficiency	• Ensure that aging infrastructure is replaced in a timely manner to minimize disruption to operations resulting from the unavailability of the equipment or facility.
Public Policy Responsiveness	• Align with objectives set out in the Ontario Building Code that aim to minimize preventable safety risks inside and outside of Ontario buildings. • Address Occupational Health and Safety considerations to ensure staff are provided with the appropriate tools to prevent injury (i.e., Musculoskeletal risk requiring ergonomic requirements for 24/7 shift environment). • Maintain NERC requirements for six sided physical security perimeter for access control to the Ontario Grid Control Centre.
Financial Performance	• Reduction of OM&A costs for break fix / remedial efforts (at project completion).

Costs:

This investment is being timed to coincide with the construction of the ISOC project to minimize cost impacts for staff relocation to a third party site, or labour premiums and enhanced work efforts to isolate areas during construction.

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	0.0	0.0	0.0	0.5	1.1	1.6
Operations, Maintenance & Administration Removals	-	-	-	-	-	-
Gross Investment Cost	0.0	0.0	0.0	0.5	1.1	1.6
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**0.0**	**0.0**	**0.0**	**0.5**	**1.1**	**1.6**

*Includes Overhead at current rates

GP-23 Integrated Voice Communications and Telephony Refresh

Start Date:	Q1 2021	**Priority:**	Demand
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	6.5
Primary Trigger:	Business Operations Efficiency		
Secondary Trigger:	Regulatory		

Investment Need:

The Integrated Voice Communications and Telephony System ("IVCT") is a mission critical system that provides voice communication management between the control centre, the IESO, Hydro One field staff, connected customers, and emergency services. The IVCT system provides integrated access and intelligent call routing via multiple communication methods incorporating multiple technologies to adequately manage the hundreds of control room calls each day. The IVCT system runs on various software, operating system, and hardware with vendor support, software patching and service lifecycles. Based on the current vendor support schedules and hardware lifecycles the IVCT system will require replacement in 2021 to maintain support and reliability of the system and the ability to recover in the event that a failure is experienced. The IVCT system allows Hydro One to meet various compliance regulations (Distribution System Code, NERC, Market Rules) that require redundant voice communications, and emergency communications that ensure constant communications paths.

The loss of voice communication between the Control Room (the primary users of the IVCT system), Hydro One customers and field staff, will result in the cancellation of planned outages and work activities until communication has been re-established. Without effective communication, there is a heightened risk to worker and customer safety (cannot dispatch emergency services or field staff), and a lack of situational awareness of local activities or external system events. This can have dire impacts on the Distribution System.

Alternative 1: Status Quo

This alternative maintains the existing IVCT system at end of life. This will expose Hydro One to reliability and sustainment risk as the current IVCT system will no longer be supported by the vendor. In addition, the ability to recover from a system failure will be negatively impacted and the maintenance cost for extended repairs or replacement components (old technology at this time) will be higher and more difficult to procure.

Witness: Colin Penny

The IVCT system is mission critical, as it handles all calls coming into and out of the Ontario Grid Control Centre ("OGCC") and Back Up Control Centre ("BUCC") control rooms. This includes communication with field staff, customers, and the IESO among others. A failure of the system would eliminate control room communication efforts, therefore impeding the operational effectiveness of the OGCC.

Alternative 2: "Off the Shelf" IP Phone

This alternative proposes the current system be replaced with generic IP phones utilized by back office staff, after the existing IVCT system reaches end of life. The generic IP phones do not have the same call handling functionalities or rolodex of frequent calls capabilities requiring additional tools and processes to ensure that control room staff efficiency is maintained and not subject to additional effort to complete the same tasks. These processes, which must be recreated for this Alternative, are more error prone and can impact employee and customer safety. Furthermore, the generic IP phones do not have any call recording capabilities to meet NERC compliance requirements. Lastly, the IVCT system includes the OGCC Interactive Voice Response ("IVR") system which is used to direct incoming calls to the appropriate OGCC department and sort calls into queue(s) for processing. To ensure normal work flow can continue, integration with the IVR system is needed. Due to the aforementioned issues and concerns, and the inability to provide needed functionality, and integration with key elements, such as IVR, this alternative has been rejected from further consideration.

Alternative 3: IVCT System Refresh Project (Recommended)

It is recommended that Hydro One proceeds with the IVCT system replacement to ensure system reliability and sustainability. This alternative provisions the necessary replacement of the IVCT system in 2021, with a "like for like" system, taking advantage of productivity enhancements, and leveraging newer technologies when the existing IVCT system has reached end of life. This will maintain operational effectiveness and reliability of the control room by maintaining the communication channels utilized daily. This will also mitigate risk of control room downtime, work execution, planned outage cancellations, and the resulting impacts on Hydro One customers that these incidents cause. Control room staff utilizes the IVCT system when coordinating storm restoration, planned system maintenance outages, fulfilling IESO notification obligations, managing helicopter services, and, most importantly, emergency response assistance for field staff and Hydro One customers.

Investment Description:

Network Operating Division operates two Grid Control Centres. The IVCT system is used on a 24/7 basis at both control centres (OGCC & BUCC) and the Operating Planning department. The IVCT system is mission critical and provides effective voice communication management from both control centres with the IESO, interconnected utilities, Hydro One customers, emergency services and field staff. Due to the critical nature of the IVCT system, and the impact of a failure on Hydro One's work execution, customer outages, responsiveness, and inability to effectively dispatch for emergencies, this system is planned to be replaced based on recommended lifecycle schedules. The failure of the IVCT system would severely impair Hydro One's ability to monitor and mitigate system events.

This investment will replace or upgrade the application software, and associated hardware (dedicated servers) at the OGCC and BUCC (which is ultimately planned to be relocated to the Integrated System Operating Centre ("ISOC")).

This investment is scheduled based on historical IT life cycles for previous instalments of the IVCT system with consideration of software, operating system, and server hardware lifecycles. An asset condition assessment review may be made closer to the investment start date to determine how best to proceed.

Risk Mitigation:

To reduce project execution risk, a pilot IVCT system will be designed and tested prior to full deployment, including parallel system use prior to final cutover. Furthermore, an experienced system integrator vendor, with expertise in deploying similar IVCT systems, will be retained to oversee the project.

Productivity enhancements and new technologies, such as automated voice-to-text capabilities, will be individually evaluated through a cost-benefit analysis closer to the project start date to ensure value for the required investment. Timing of this activity is required prior to commencement, as technologies and improved functionality today may differ significantly in 2020/2021.

Witness: Colin Penny

Result:

This investment will ensure reliability of the IVCT system and promote productivity in the control room while meeting all regulatory requirements. The IVCT is set with user friendly touchscreen interface, quick dial functionalities, and a customized Rolodex contact database to help controllers do their job more accurately, more efficiently, and faster. The IVCT helps Hydro One operations meets its obligations under the OEB Distribution System Code, IESO Market Rules, and NERC (see Public Policy Responsiveness section below for full details).

Outcome Summary:

Customer Focus	• Support customer reliability by maintaining low call handling time and fast storm restoration response. • Keep customers informed of outage status using Autodialer functions and therefore improving customer satisfaction.
Operational Effectiveness	• Allows Hydro One control room staff to more efficiently co-ordinate storm restoration, protection maintenance work, system events with field staff, other LDC, and end use customers. • Ensure effective response and minimizing outage times.
Public Policy Responsiveness	• Allow Hydro One to meet obligations under OEB Distribution System Code (Section 4) regarding operations requirements. • Allow Hydro One to meet obligations under IESO Market Rules (Part 7.3) regarding outage management procedures. • Allow Hydro One to meet event reporting and investigation obligations as specified in NERC standard EOP-004, and COM.
Financial Performance	• Effective communications ensure the quickest dispatch for faster restoration times which translates into less hours spent by field crews during unscheduled events, reducing field costs.

Costs:

This is a reoccurring investment and the budget cost has been determined based on estimates by the Power System Information Technology ("PSIT") division utilizing historical IVCT investments. Based on lessons learnt from previous IVCT projects, this proposed budget takes into consideration all relevant costs (including license fees, changes to interest/overhead charges) which may not be initially obvious. The ongoing sustainment upkeep cost of the new IVCT system will have to be submitted by prospective vendors as part of their solution proposal. The OM&A cost for the current IVCT system is approximately $1 million annually. Hydro One will strive for the new IVCT system to have OM&A cost equivalent to the current system or less. Final costs of the project are influenced by the change in technologies and costs associated with the infrastructure supporting it, including market pricing at that time. Technological uncertainties and obsolescence are always a challenge for capital projects that are expected to start four to five years later. Hydro One is continuously monitoring technological developments and industry best practices to ensure the most cost effective solution.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	-	-	3.0	3.5	6.5
Operations, Maintenance & Administration Removals	-	-	-	-	-	-
Gross Investment Cost	-	-	-	3.0	3.5	6.5
Less Capital Contributions	-	-	-	-	-	-
Net Investment Cost	**-**	**-**	**-**	**3.0**	**3.5**	**6.5**

**Includes Overhead at current rates.*

Witness: Colin Penny

GP-24 Station Security Upgrades

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Q4 2022	**Plan Period Cost ($M):**	5.7
Primary Trigger:	Security		
Secondary Trigger:	Safety		

Investment Need:

Grounding systems are used in stations to safely dissipate fault currents into the ground in the event of equipment failure and to safely dissipate neutral currents into the ground to protect Hydro One employees and the public. Copper in station and fence grounding systems, ground connections and neutral connections for electrical equipment are often targeted for theft in Hydro One distribution stations. The removal of ground and neutral copper connections compromises the electrical integrity of the grounding system. This can pose safety hazards to Hydro One employees and the general public, which can result in physical injury, including death.

Thieves have gained access into stations by cutting through chain-link fence fabric or breaking lock mechanisms. This investment addresses break, enter and theft at stations through the installation of improved security measures to reduce such occurrences. These upgraded security measures will improve health and safety, benefiting Hydro One employees and the general public.

The Distribution Station Security Upgrades investment addresses the need to implement increased security methods to mitigate break, enter and theft occurrences within distribution stations.

Alternative 1: "No Funding Alternative"

If no funding is provided to allow for security upgrades in distribution stations, then stations will continue to have break-in occurrences, and copper and neutral grounds will continue to be stolen. Hydro One maintenance staff will continue to replace the stolen grounds under corrective maintenance programs, and thieves will continue to return to the same stations to steal the ground and neutral conductors once they are replaced, jeopardizing the health and safety of those involved.

Urban stations are inspected by maintenance staff monthly and rural stations are inspected every 6 months. If station fences are cut, locks are broken and/or grounds are stolen, the public could be exposed to these dangerous conditions until the next station inspection.

Alternative 2: Install Security Upgrades *(Recommended)*

The preferred alternative is to install security upgrades including more robust perimeter protection and alternatives to copper in distribution stations to deter break and enter occurrences, and prevent thieves from stealing copper grounds and neutral conductors in specific areas. Installation of security upgrades will mitigate the exposure of the public to compromised grounding systems, as well as compromised station perimeters.

Investment Description:

The scope of work for this investment involves the installation of upgraded security measures at distribution stations to mitigate break and enter occurrences, and prevent thieves from stealing copper grounds and neutral conductors. Over the past five years, there has been 120 break, enter and/or theft occurrences at Hydro One distribution stations. During this period, the total number of occurrences has been reduced by 50% through minor security upgrades which are addressing fence perimeter grounding. However, break and enter occurrences have been increasing each year. Yearly candidates for distribution station security upgrades under this investment will include those which have had multiple break, enter and/or theft occurrences in recent years. The proposed funding level will allow for three stations to receive major security upgrades each year over the planning period. The major security upgrades will mitigate break and enter occurrences in addition to addressing perimeter grounding. Stations which are candidates for station refurbishment projects will also be considered for major security upgrades.

Risk Mitigation:

The risk associated with completion of the security upgrades projects includes the lead time required to procure the security upgrade materials, which Hydro One does not typically purchase. Completion of the projects within the planned years could be at risk if long lead time materials are not procured in a timely matter. The risk is mitigated by the procurement of long lead time materials in the year before the project is planned for completion, to allow the construction to be completed in the planned year.

Result:

Station security upgrades will result in the following:

- Break, enter and copper theft occurrences at stations which have received multiple occurrences in recent years will be mitigated;
- The electrical integrity of station and fence grounding systems in distribution stations will be preserved, allowing for the safe dissipation of fault currents and neutral currents into the ground;
- Exposure of the public to compromised station perimeters and grounding systems will be mitigated; and
- The safety of Hydro One employees and the general public will be improved.

Outcome Summary:

Customer Focus	• Improve integrity of station perimeters and grounding systems to maintain public safety.
Operational Effectiveness	• Maintain safe operation of distribution stations by addressing stations with multiple break, enter and theft occurrences. • Introduction of innovative ways of upgrading security measures to reduce theft.
Public Policy Responsiveness	• Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during station inspections.
Financial Performance	• Reduce high cost of material theft; primarily copper.

Costs:

Factors affecting the cost of each project can include the type, manufacturer and magnitude of the material to be installed. Vendors with the most cost effective and practical material will be selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	1.2	1.2	1.2	1.2	1.3	6.1
Less Removals	0.1	0.1	0.1	0.1	0.1	0.5
Gross Investment Cost	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**5.7**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**1.1**	**1.1**	**1.1**	**1.2**	**1.2**	**5.7**

**Includes Overhead at current rates.*

GP-25 Leamington TS Capital Contribution

Start Date:	Q2 2016	**Priority:**	High
In-Service Date:	Q2 2018	**Plan Period Cost ($M):**	2.2
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Load Growth		

Investment Need:

To increase transformation capacity to accommodate the forecast customer load growth and to improve reliability in the Windsor-Essex region, as documented in the Windsor-Essex Regional Infrastructure Plan as well as in Exhibit B1, Tab 3, Schedule 11, ISD# D-14 of Hydro One's 2017-2018 cost of service transmission application (EB-2016-0160). Not proceeding with this investment would result in further degradation of load supply reliability in the region.

Alternatives:

Alternative 3 was approved by the Ontario Energy Board under s.92 application for the transmission investment (EB-2013-0421).

Alternative 1: Do Nothing

This alternative is not recommended because Hydro One Distribution would not be able to meet the supply needs for normal load growth and the additional capacity requirements for large distribution load customers and distributed generation customers.

Alternative 2: Build a New Transformer Station near Woodslee Junction and Upgrade the 115 kV Connection Line Supplying Kingsville TS

One alternative is to strengthen the existing 115 kV system and replace the assets reaching their end of expected service life. The existing 115 kV transmission system would be strengthened by building a new transformer station near Woodslee junction and upgrading the 115 kV connection line between the new TS and Kingsville TS. The three transformers at end of expected service life at Kingsville TS would be replaced like-for-like. In addition, two new feeders would be built to address the load growth in Leamington. This alternative is not recommended because the total project cost would be approximately $97 million, which is significantly higher than the recommended alternative.

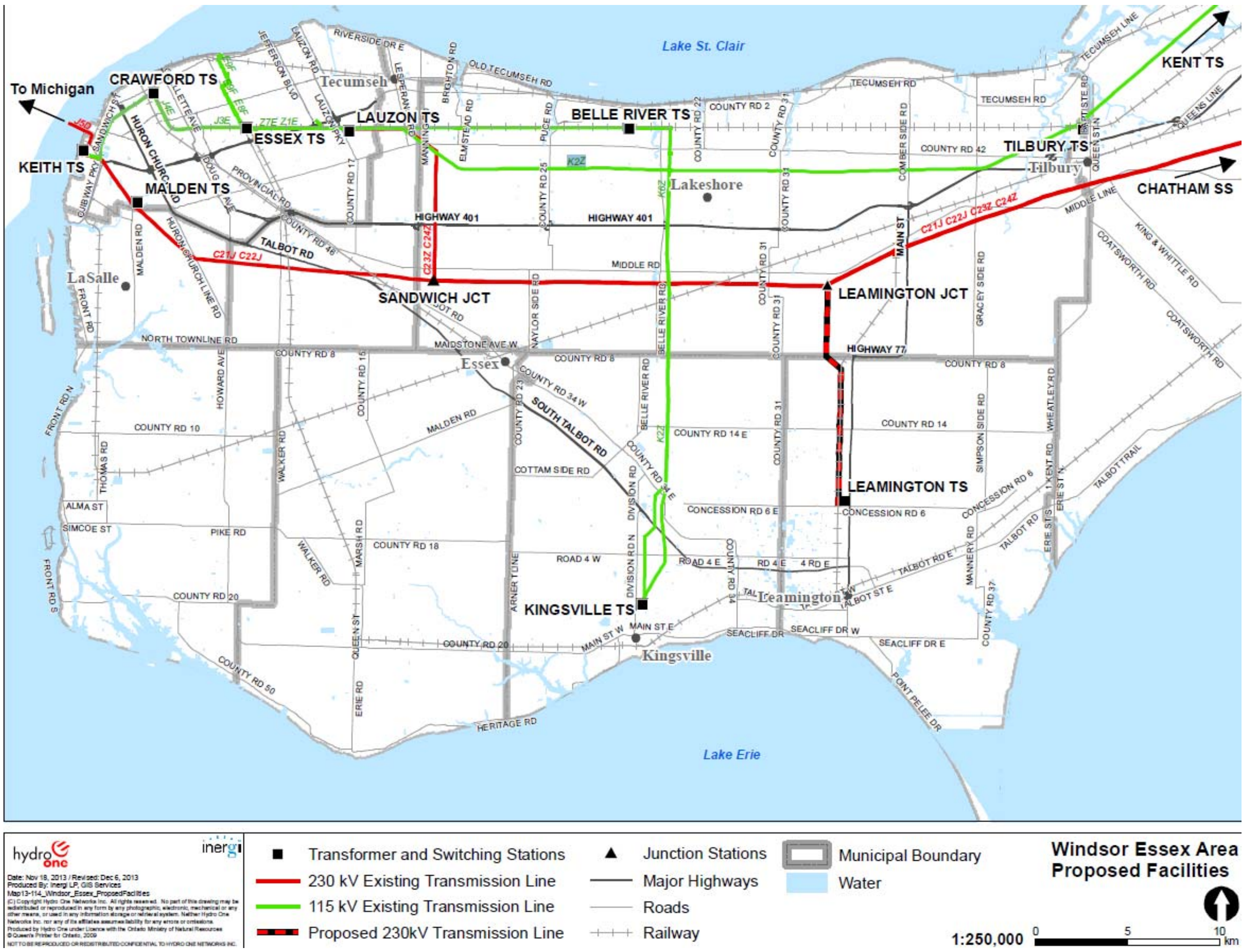
Alternative 3: Supply to Essex County Transmission Reinforcement ("SECTR") project *(Recommended)*

The preferred alternative is to build a new 230 kV – 27.6 kV DESN station at Leamington TS. This alternative offers significant reliability, efficiency and operational improvements. It enables the decommissioning of two of the transformers at Kingsville TS that are reaching the end of their expected service life, and replacement of a third which has also reached its service life. It also addresses the concerns with limited thermal capacity and short circuit levels. Furthermore, distribution feeder lengths supplying the Leamington area would be reduced from 15-20 kilometres to 5-10 kilometres, providing improved supply reliability, supply voltage and reduced line losses. This alternative meets all the identified transmission system needs as well as providing additional capacities for both load growth and distributed generation. The total project cost would be approximately $72 million with a Hydro One Distribution capital contribution of $21 million. It is expected that a portion of the contribution will be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area, subject to OEB approval under the Regional Planning and Cost Allocation proceeding (EB-2016-0003).

Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area. This investment provides the most cost effective solution for meeting the needs in the Kingsville-Leamington area and the surrounding Windsor-Essex area.

Investment Description:

The map below depicts the existing and proposed electricity transmission systems in the area:



The preferred solution includes construction of a new transmission station, Leamington TS and approximately 13 kilometres of new 230 kV double-circuit line. The installation of a new 230 kV – 27.6 kV DESN at Leamington improves reliability, provides capacity to accommodate the load growth within the Kingsville-Leamington area, and provides restoration capability for the Windsor-Essex area. With the new DESN in the area, Kingsville TS capacity can be reduced. Only one of the three transformers at the end of their expected service life will be replaced and the other two transformers will be decommissioned.

Hydro One Transmission will build the new Leamington TS and the new 230 kV double-circuit line and they have already commenced work on the project. Hydro One Distribution will pay capital contributions to Hydro One Transmission. A portion of these contributions is anticipated to be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area. The capital contribution amounts provided in the "Costs" section below are preliminary and will be determined and finalized in accordance with the Transmission System Code.

Risk Mitigation:

This project is subject to the outcome of the Regional Planning and Cost Allocation Review proceeding (EB-2016-0003) which is currently before the OEB. The cost table below is based on the latest estimate of project cost, and assume the OEB approves the Hydro One proposed methodology described in its application for leave to construct a new transmission line and facilities in the Windsor-Essex Region (EB-2013-0421). Revised project costs or approval of a different cost allocation methodology may affect these numbers.

Hydro One Distribution has been in direct contact with affected LDCs and Hydro One Transmission on the SECTR project since the Windsor Essex Regional planning initiative began in 2014. Furthermore, Hydro One Distribution met with the impacted LDCs in March 2016 to review the distribution work in the SECTR project and the overall transmission project status.

Result:

- Increase transformation capacity to meet future load requirements for the Kingsville-Leamington area as per section 3.3.1 of the Distribution System Code;
- Improve operational effectiveness by increasing reliability of supply for customers in the Kingsville-Leamington area and the surrounding Windsor-Essex area; and
- Savings financially through reduction in costs and resources by addressing multiple issues simultaneously.

Outcome Summary:

Customer Focus	• Increase capacity to allow connection of large distribution customers and promote economic development in the area. • Allow more distributed generation customers to connect to the system.
Operational Effectiveness	• Leamington TS will provide 230kV service in the area and shorten feeder lengths which increase efficiency and reliability of the system.
Public Policy Responsiveness	• Meet the requirements of the Distribution System Code and distribution license to respond to embedded LDCs and large customer requests for increased capacity and to accommodate load growth.
Financial Performance	• Cost savings are realized by addressing multiple issues simultaneously in one project.

Costs:

The estimated cost of the contribution to the project is based on detailed estimates prepared by Hydro One Transmission, which have been determined using a cost allocation methodology submitted to the OEB for approval in proceeding EB-2016-0003. In the current planning period, the capital contribution to Hydro One Transmission is approximately $21 million. Of this amount, the LDC's and large customers' share is approximately $14 million, and Hydro One Distribution's share is approximately $6.7 million.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs******
Capital* and Minor Fixed Assets	6.7	-	-	-	-	6.7	20.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**6.7**	-	-	-	-	**6.7**	**20.6**
Less Capital Contributions	4.5	-	-	-	-	4.5	13.9
Net Investment Cost	**2.2**	-	-	-	-	**2.2**	**6.7**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-26 Hanmer TS Capital Contribution

Start Date:	Q2 2017	**Priority:**	Medium
In-Service Date:	Q1 2019	**Plan Period Cost ($M):**	3.7
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Failure Risk		

Investment Need:

To address end-of-life assets, load growth and reliability in the East Sudbury area. The corresponding transmission investment was described in Exhibit B1, Tab 3, Schedule 11 of Hydro One's 2018-2018 transmission cost-of-service application (investment summary document #D18).

There are a range of needs to be addressed in the northeast Sudbury region including:

- The Valley East community within the City of Greater Sudbury has experienced steady load growth and is expected to continue growing at 2% per year. Martindale TS M6 is presently approaching its planned loading limit;
- Martindale TS M6 feeder is in poor condition and has demonstrated very poor reliability. There are also accessibility issues as portions of the M6 feeder are off-road through a mining reserve;
- Hydro One Transmission has concluded that the T2 and T3 transformers at Coniston TS are reaching end of life, and in need of replacement. The transformers are 76 and 67 years old, respectively. Coniston TS currently feeds a 22 kV network, which is an obsolete sub-transmission voltage that does not exist anywhere else in the province. The 22 kV network is an electrical island which cannot be supplied from any other source. When an outage occurs, the load cannot be easily restored due to lack of a back-up supply. All new 22 kV load connections in the past 20 years have been equipped with dual-voltage transformers for eventual operation at 44 kV; and
- Clarabelle TS M7 and Coniston TS M1 have exhibited poor reliability for feeders supplying an urban area with a large number of commercial and industrial customers.

The transmission needs at Coniston TS and Martindale TS presented an opportunity for Hydro One Distribution to work with the transmitter, Hydro One Transmission, and review the transmission connection facilities in order to determine the most appropriate and cost-effective options for meeting needs in the area.

Alternative 1: Do Nothing

This alternative is not acceptable because it will not resolve the issues in the area. In addition to being one of the worst performing feeders in the province, sections of the Martindale TS M6 feeder are in poor locations and difficult to access. Coniston TS operates at 22 kV, an obsolete voltage level, and the two transformers are reaching end of life. Furthermore, Clarabelle TS M7 and Coniston TS M1 have poor reliability for feeders supplying an urban area with a large number of commercial and industrial customers.

Alternative 2: Replace Assets Reaching End of Life on a Like for Like Basis

One alternative is to retain the existing system configuration and replace assets reaching end of life. The transformers at Coniston TS could be replaced with new 22kV units. A new feeder could be built and double circuited with the M6 to address any future overloading on the Martindale TS M6. The Martindale TS M7 would be rebuilt double circuiting with Martindale TS M6 and Clarabelle TS M7. While this would be a less expensive replacement alternative, it would not be cost effective because retaining a 22 kV voltage requires continued use of non-standard equipment leading to higher costs and limited suppliers. The shortage of supply of non-standard equipment often leads to prolonged outages. Not standardizing the voltage will eventually lead to deteriorated reliability and reduced operational efficiency in the area.

Alternative 3: New Assets at Hanmer TS *(Recommended)*

The preferred alternative is for Hydro One Transmission to build two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS to supply the Valley East load currently connected to longer feeders out of Martindale TS and Clarabelle TS. Coniston TS would be decommissioned, by converting its load to 44 kV and connecting it to Martindale TS M6 feeder.

Alternative 3 costs approximately ten percent more than Alternative 2, but offers more benefits, specifically, significant reliability, efficiency and operational improvements. Alternative 3 allows for elimination of the non-standard 22 kV operating voltage in Coniston, and provides new connection capacity right in the Valley East load center making it much better positioned for future growth in this area as well as the rest of the north-east Sudbury area. Alternative 3 reduces the length of 44 kV feeders supplying the Valley East area from 20-25 km in length to less than 2 km. Therefore, Alternative 3 is more cost effective.

Under Alternative 3, feeder lengths supplying the Hanmer area would be reduced from 12-14 km to about two kilometres, which would reduce line exposure to faults and improve reliability. Line losses would be reduced by 40%. This alternative also allows for the elimination of the non-standard 22 kV operating voltage at Coniston TS and provides new connection capacity to accommodate forecast load growth in the area and new generation.

This investment provides the most cost effective solution for meeting the needs in northeast Sudbury. The two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS provide an alternate solution to simply replacing assets in the area. Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area.

Investment Description:

To meet growing customer load in Valley East and address assets reaching end of life at Coniston TS, Hydro One will redirect load from Coniston TS to Martindale TS. It will then redirect Valley East load from Martindale TS and Clarabelle TS to Hanmer TS. This will involve:

1. Hydro One Transmission constructing two new 50/83 MVA step-down transformers and associated switchgear at Hanmer TS to supply Valley East load;
2. Hydro One Distribution conversion of the northeast Sudbury area supply to 44 kV; and
3. Hydro One Transmission decommissioning the existing Coniston TS.

The map below depicts the existing and proposed electricity transmission and distribution systems in the area:

The preferred solution is for Hydro One Transmission to construct two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS, which is an existing 500kV – 230kV station connected to the Bulk Electricity System. This new installation at Hanmer TS would replace end-of-life station assets, improve reliability, and provide capacity to accommodate the load growth within the City of Greater Sudbury. This would provide Martindale TS with the capacity to service the Coniston area for both load and generation (for example allowing an increase in existing hydraulic generation), removing the requirement to replace the assets reaching their end of life at Coniston TS.

The existing Clarabelle TS M7 and Martindale TS M7 feeders and the Valley East Branch of the Martindale TS M6 feeder would be transferred to Hanmer TS. The placement of the two new 230/44 kV step-down transformers and associated switchgear at Hanmer TS would remove the requirement to rebuild the Martindale TS M6 and M7 feeders on-road. Hanmer TS would also provide new connection capacity in the Valley East load centre to better accommodate future load growth in the northeast Sudbury area. This solution would also eliminate Coniston TS by extending Martindale TS M6 and converting the load to 44kV.

The capital contribution amount from Hydro One Distribution to Hydro One Transmission is considered preliminary and will be determined and finalized in accordance with the Transmission System Code once the Capital Cost Recovery Agreement is signed and the project is placed in service.

Risk Mitigation:

The main risks to completion of this work are lack of labour resources for design and construction. These risks will be mitigated by ensuring appropriate planning lead times are followed for project scheduling and by considering constructability issues early in the project definition stage.

Result:

- Increased transformation capacity to meet future load requirements;
- Improved reliability of Martindale TS M6 feeder; and
- Improved operating efficiency by eliminating obsolete 22kV operating voltage from Coniston TS and the Hydro One system.

Outcome Summary:

Customer Focus	• Accommodate customer load growth and improve reliability in the Greater Sudbury area.
Operational Effectiveness	• Improve operating efficiency by eliminating obsolete 22kV voltage from Coniston TS.
Public Policy Responsiveness	• Comply with license requirements to respond to load growth needs.

Costs:

The estimated cost of the contribution to the project is based on planner's estimates prepared by Hydro One Transmission.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	3.4	0.3	-	-	-	3.7	5.4
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**3.4**	**0.3**	-	-	-	**3.7**	**5.4**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.4**	**0.3**	-	-	-	**3.7**	**5.4**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-27 Enfield TS Capital Contribution

Start Date:	Q2 2017	**Priority:**	High
In-Service Date:	Q2 2019	**Plan Period Cost ($M):**	3.0
Primary Trigger:	System Capital Investment Support		
Secondary Trigger:	Load Growth		

Investment Need:

To increase transformation capacity to accommodate the forecast customer load growth and to improve supply reliability in the Oshawa – Clarington area, as documented in the GTA East Regional Infrastructure Plan and Hydro One's 2017-2018 transmission cost-of-service application Exhibit B1, Tab 3, and Schedule 1, investment summary document #D21. Not proceeding with this investment would result in inadequate supply capacity in the area.

Alternative 1: Do Nothing

This alternative is not recommended because Wilson TS is currently overloaded and is expected to exceed its capacity by a significant amount due to load growth and increased generation in the Durham region.

Alternative 2: Upgrade Wilson TS

This alternative requires upgrade of Wilson TS to provide additional supply capacity in the area. This alternative addresses the Hydro One Distribution short-term capacity needs in the area. However, based on the load forecast, it will result in shortfall of supply capacity in another ten years. Also, this alternative would potentially result in high costs due to development of new distribution feeders in developed and congested surroundings.

Alternative 3: Contribute to Build New Enfield TS (Recommended Alternative)

The recommended solution is to contribute to a new transmission station at Enfield TS to provide the capacity required to accommodate long-term growth. The feeders out of Enfield TS will also diversify the feeder routes and increase load transfer flexibility for improved outage response times and increased reliability in the region.

Investment Description:

The proposed plan is to build a new 230/44 kV 170 MVA transformer station at Enfield TS with 44 kV feeders shared between Hydro One Distribution and Oshawa PUC to serve the increasing needs in the Region of Durham and City of Oshawa. The Enfield TS will have provision for two future additional 44 kV feeders. The overloading at Wilson TS will be addressed by transferring some load to the two new Hydro One Distribution feeders at Enfield TS. The new feeders will also improve reliability in the region by diversifying feeder routes. Additional load transfer options between Wilson TS and Enfield TS will reduce the number and duration of outages.

Hydro One Distribution and Oshawa PUC will be required to pay their portion of the capital contribution to Hydro One Transmission. The capital contribution amounts provided under the "Costs" section of this document are considered preliminary and will be determined and finalized in accordance with the Transmission System Code.

Risk Mitigation:

At this point of time, the contribution cost to Enfield TS is based on planner's level estimate. The total contribution cost will be determined once the cost estimate for the Enfield TS is available, and actuals will be determined after the completion of Enfield TS project work.

Result:

- Increased transformation capacity to meet future load growth requirements; and
- Improved supply reliability by increasing redundancy of transmission supply.

Outcome Summary:

Customer Focus	• Increased reliability of supply to existing customers in the Durham area. • Accommodate connection of future customers.
Operational Effectiveness	• Improved supply reliability by increasing redundancy of transmission supply and by diversifying feeder routing to allow for better load transfer capability.
Public Policy Responsiveness	• Meet the requirements of the DSC and Distribution Licence to provide increased capacity to meet load growth.
Financial Performance	

Costs:

The estimated cost of the contribution to the project is based on budgetary cost estimates prepared by Hydro One Transmission.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	2.0	1.0	-	-	-	3.0	5.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**2.0**	**1.0**	-	-	-	**3.0**	**5.0**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**2.0**	**1.0**	-	-	-	**3.0**	**5.0**

**Includes overhead at current rates. ** Total Project includes amounts spent prior to 2018. This cost estimate has been modified since the last Hydro One distribution rate application (EB-2013-0416) based on updated estimates provided by Hydro One Transmission.*

GP-28 Call Centre Technology

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Program	**Plan Period Cost ($M):**	17.5
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One has two call centres. One is located in Markham, Ontario and the other is located in London, Ontario. Billing and service inquiries are handled from 7:30 am to 8:00 pm, Monday to Friday in the call centres. Hydro One also offers a 24 hour emergency hotline to report power outages, fallen trees or other emergency issues.

To handle these calls, the call centre relies on technology to operate effectively. Key systems that the call centre relies upon include the Interactive Voice Response ("IVR") System, the Computer Telephony System and SAP CRM / iCare System. IVR is an automated telephony system that interacts with callers, gathers information through voice prompts and routes calls to the appropriate recipient. The Computer Telephony Integration ("CTI") allows interactions on a telephone and a computer to be integrated or coordinated.

Hydro One uses SAP Customer Relationship Management for its customer information system integrated with an interface called iCare. When a customer calls the call centre, the screen that pops up with customer information is iCare gathering information from the underlying SAP CRM system. Through SAP CRM / iCare, the call centre agent is able to access wide amounts of data and handle most all customer inquiries (manage account information, provide billing information, maintain budget billing, payment and collections, etc.) in a fast and efficient manner.

Hydro One's CTI & IVR systems were last replaced in 2004 and there were subsequent enhancements to the IVR system since then. The CTI & IVR technology allows Hydro One's customer information system ("CIS") to interact with the telephone system used by the call centre as well as other forms of communication (email, text messaging, web messaging, fax, etc.). There have been advances in technology in this space since the previous implementation such as better analytics and speech recognition. Words spoken by the caller are used to determine what command to execute or which agents to route the calls to. This allows for a better customer experience since this will result in less likelihood that the call will have to be transferred from one agent to another, thereby reducing the time the customer has to be on the call. Newer systems also offer more effective monitoring of agent, department and call centre performance.

The CTI & IVR system that Hydro One uses is past the recommended service life of 5 – 7 years. The current IVR is at risk of not being supported by vendors from a break fix perspective. Extended maintenance contracts only address existing defects but will not develop or release new code for legacy versions of software. The extended maintenance contract for the CTI&IVR systems will not cover any new code development for any issues experienced during normal operations. This introduces a high risk around recovery time when system outages are experienced, thus in turn impacting not only the customers who have billing or service related inquiries, but also those who are calling to report emergencies.

The SAP CRM system went live in 2013. Technology changes at a fast pace. This investment is required to implement system enhancements from the vendor to keep current and ensure continued functionality for customers. The enhancements are discussed in the various alternatives below.

Alternative 1: Status Quo

This alternative would continue to operate with the current CTI/IVR system and refrain from investing in the newest SAP upgrades.

The existing system was last replaced in 2004. If the status quo alternative was selected, Hydro One would continue to rely on existing systems that are past their recommended useful life. Not retaining systems in vendor supportable levels prevents Hydro One from enforcing Service Level Agreements (SLA) with our outsourced partner in the event of an outage or issue. As the vendor would not be able to release new code for legacy software, Hydro One would be unable to have our outsourced service partner maintain key system uptime SLA's. If the system is unavailable, our customers will potentially be unable to reach the call centre, which directly impacts customer satisfaction.

Status quo would also mean there no enhancements to SAP CRM / iCare. Enhancements are new functionality or improvements to existing functionality that SAP develops. These are rolled out in terms of patches (minor enhancements) or upgrades (significant changes to the software). Enhancements improve customer’s experience. In addition, for SAP to support the application, Hydro One needs to be at a certain software level.

Witness: Colin Penny

Alternative 2: Upgrade the Telephony Technology Suite (Recommended)

This alternative would replace the aging CTI and IVR technologies and enhance the existing SAP CRM / iCare System.

This investment is recommended since it will replace end of life technology in the call centre and improve customer interaction on various platforms. The enhancements in SAP CRM / iCare will provide improved service to customers who call our call centre and ensure that the software continues to be supported by SAP. Improvements to the overall customer experience are discussed in the Result and Outcome sections below.

Investment Description:

This includes both hardware and the software replacements, including a possible switch to a cloud-based solution or a hybrid consisting of on-premise and off-premise hardware/software. This investment will also introduce new call routing and call monitoring capabilities for Hydro One's commercial and industrial customers.

This investment also covers the funding required to implement enhancements to Hydro One's SAP CRM / iCare system.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected. Thorough testing will be performed to minimize system defects which can impact customers significantly – from ability to reach the call centre, get calls routed to the proper agent and system enhancements that otherwise would improve the ability to serve our customers.

Result:

The primary driver for this investment is to ensure reliability of Hydro One's technology within the call centre. Since these systems are past their recommended useful life, they are more prone to system failure.

Upgrading this technology will improve customer service with modern speech recognition and text-to-speech technologies, more intuitive graphical user interfaces, improved performance, integration of relevant caller information into a unified dashboard, more efficient call routing, more effective monitoring of call centre agents, and more effective monitoring of call centre performance.

Implementing enhancements will also result in improvements in how we serve our customers. Based on feedback received during Hydro One's Customer Consultation, commercial and industrial customers were dissatisfied with the level of customer service. The end result of these investments will be improved customer communication and satisfaction.

Outcome Summary:

Customer Focus	• Ensure a reliable system is available for customers. • Improve customer service with modern speech recognition and text-to-speech technologies, thereby improving how call centre agents interact with customers.
Operational Effectiveness	• Improve performance and provide more efficient call routing inside the call centre. • Integrate relevant caller information into a unified dashboard.
Public Policy Responsiveness	• Ensure that emergency services continue to be available to customers on a 7/24 basis.
Financial Performance	• Provide better call centre analytics to improve performance and lower cost.

Costs:

The final cost of the project covers deliverables and supports activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the solution.

This project has a high degree of complexity; it includes a new technology platform and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital and Minor Fixed Assets	7.5		7.2	2.9		17.5
Less Removals						
Gross Investment Cost	**7.5**		**7.2**	**2.9**		**17.5**
Less Capital Contributions						
Net Investment Cost	**7.5**		**7.2**	**2.9**		**17.5**

GP-29 Customer Service Billing Investments

Start Date:	Q4 2021	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	10.4
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One's paper bill is the most common communications vehicle with customers. About 14 million invoices are mailed annually to customers.

Hydro One's 2016 survey results indicated that only 62% of customers find their bill easy to understand. The design of the current bill has been identified by customers as a weakness and an area of opportunity (via customer satisfaction surveys and the Distribution Customer Engagement results the Ontario Ombudsman, and Hydro One's Ombudsman). As a result, Hydro One is introducing a redesigned bill in 2017. Additional capital funding will be required in 2022 to introduce further enhancements to ensure customers remain satisfied and understand their bill.

In addition to the need for producing bills that customers find easier to understand, there's also a need to improve billing for non-energy services. Hydro One provides specialized work for non-energy services to external parties. These include:

1. IESO Charges;
2. Retailer Settlements;
3. Secondary land use;
4. Land corridor leases;
5. Training for other municipalities and utilities;
6. Damage claims;
7. Trouble calls / Storm damage;
8. New service connections;
9. Service Upgrades;
10. Forestry Clearing;
11. Distributed Generation & MicroFit set up;
12. Long term load transfer;
13. Key Account Management connected customers (i.e. Ontario Power Generation);
14. Joint use pole rentals; and

15. Stations Modifications.

A review of the non-energy billing process identified inconsistencies in how the various non-energy services are handled. There is also inconsistency on the customer service policies between energy related billing versus non-energy related billing. The processes, tools and technology for non-energy billing are inefficient.

Alternative 1: Status Quo

Hydro One could elect not to embark on another bill redesign project in 2022 and not to integrate its non-energy billing practice in 2021. This alternative was considered and rejected because Hydro One is committed to improving its' relationship with its customers.

Alternative 2: Redesign Customer Bills and Improve Non-Energy Billing (Recommended)

This alternative is recommended since this will enhance customer service. The bill redesign project will improve customer understanding of their bill and more effectively promote and market new programs and services. The Non-Energy Billing investment will ensure consistency with energy billing customer service policies and will improve customer satisfaction.

Investment Description:

This investment is required to fund the following initiatives:

1. Bill Redesign – The Hydro One bill will be redesigned in 2022 to make it easier for customers to understand. The redesigned bill will also encourage energy conservation by providing customers information on how they can manage their usage better to take advantage of off-peak rates; and
2. Non Energy Billing Enhancements – Hydro One generates bills for the following non-energy services: damage claims, new service connections, service upgrades, forestry clearing, Distributed Generation and MicroFit set up, joint use pole rentals, secondary land use, land corridor leases, etc. This investment is required to enhance the entire end-to-end process, including invoicing, collections, and customer service.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

<u>Risk of Customers Not Trusting Their Bills</u>

For the Bill Redesign Project, one risk of implementing this project is the customers may again not trust the billing system if there are any issues during implementation. The Bill Redesign Project will not change how the bill is calculated. It will only change how the bill is presented. Energy billing redesign will continue to comply with prescribed provincial regulation. Yet any defects during implementation may cause customers to believe that their bill is not being calculated properly. This risk will be minimized through thorough testing and by hiring consultants who have expertise in bill print functionality.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. In addition, follow up workshops will be conducted at appropriate project stage gates.

Result:

Redesigning the Hydro One bill will make it easier for customers to understand the bill. As a result, it is expected to lower calls to the call centre and improve customer satisfaction. It will also encourage energy conservation as the bill will break down consumption based on on-peak and off-peak usage.

The Non-Energy Billing investment is expected to improve the entire end-to-end process, including invoicing, collections, and customer service. For example, these customers do not have access to electronic bills or self-service capabilities. New tools, processes, and technology will improve customer satisfaction.

Outcome Summary:

Customer Focus	• Improve customer experience and satisfaction through bills that are easier to understand.
Operational Effectiveness	• Reduce calls to the call centre through reduction of billing related questions and reducing call centre costs overall. • Ensure consistency between energy billing customer service policies and non-energy billing.
Public Policy Responsiveness	• Encourage energy conservation as bills will better display usage consumption into on-peak & off-peak hours.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as Hydro One direct and indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	-	-	-	4.5	5.9	10.4	15.0
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	-	-	-	**4.5**	**5.9**	**10.4**	**15.0**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	-	-	-	**4.5**	**5.9**	**10.4**	**15.0**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

Witness: Lincoln Frost-Hunt

GP-30 Customer Service Regulatory Related

Start Date:	Q1 2018	**Priority:**	Demand
In-Service Date:	Multiple	**Plan Period Cost ($M):**	14.0
Primary Trigger:	Public Policy Responsiveness		
Secondary Trigger:	Customer Focus		

Investment Need:

This investment would implement the Demand to Interval change which is required by the Ontario Energy Board. It would also implement the Dynamic Pricing Pilot which is a pilot program offered by the government to encourage energy conversation.

Alternatives:

This investment would implement the Demand to Interval change which is OEB required. This is a non-discretionary investment. It would also implement the Dynamic Pricing Pilot which is a pilot program offered by the government to encourage energy conversation. Finally, it will implement the new rate design for Commercial & Industrial customers. This new rate is not OEB required. Hydro One will seek OEB's approval, via current process for changing rates, for this new rate design which is intended to encourage energy conservation among Commercial & Industrial customers.

Not performing the mandated changes, such as 'Demand to Interval Meter' that is non-discretionary, means Hydro One will not be compliant with regulatory changes.

For the Dynamic Pricing investment, while not specifically required by regulatory code at this time, Hydro One proposes to implement the pilot program offered by the government to encourage energy conservation. This will assist the government in its efforts to address the issue of high electricity cost in Ontario.

Investment Description:

This investment will implement the following regulatory and government changes and introduce pricing options for customers:

1. Demand to Interval Migration - Funding is required to implement system changes to support the Distribution System Code amendments that came into force on August

21, 2014. Section 5.1.3 requires a distributor to install an interval meter on any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW and pay the hourly Ontario energy price from the IESO-administered real-time energy market based on their actual usage by August 21, 2020.

2. Dynamic Energy Pricing - On July 18, 2016, the Ontario Energy Board (OEB) issued its Regulated Price Plan Roadmap: Guideline for Pilot Projects on RPP Pricing. Hydro One submitted an application to develop and implement price and non-price pilots, including the continuation of Hydro One's existing pilot which allows customers to have different variations of Time of Use rates. Dynamic Energy Pricing encourages customers to reduce electricity usage and shift usage away from peak hours. Some participants also receive enabling technologies such as Wi-Fi thermostats and in-home displays to assess the associated incremental savings. On September 23, 2015, the OEB agreed that there is value in extending Hydro One's existing pilot until April 30, 2017. Capital funding is required to extend the pilot beyond April 2017.

3. New Rate Design for Commercial and Industrial Customers - Hydro One plans to develop an innovative rate design for commercial and industrial customers that incents customers and influences their behavior. This is not OEB required but is included in this Investment Summary Document as this will require approval from the OEB before the new rate is changed.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective platform. As such, a market scan will be conducted to determine best-in-class programs. Hydro One will also engage with customers to solicit input and ensure their needs are met.

The timing of this investment is based on the need to comply with upcoming regulatory changes and introduce programs to assist customers with their electricity costs and affordability issues.

Result:

This investment will ensure Hydro One complies with regulatory and government changes. This investment will also provide customers with new pricing options, thereby reducing affordability issues for customers.

Outcome Summary:

Customer Focus	• Make electricity more affordable and improve customer satisfaction through the new pricing model. • Reduce electricity cost by encouraging usage in off-peak hours. • Improve customer satisfaction by providing enabling technologies such as Wi-Fi thermostats and in-home displays to assess the associated incremental savings.
Operational Effectiveness	
Public Policy Responsiveness	• Encourage energy conservation by incenting customers to reduce electricity usage and shift usage away from peak hours. • Comply with regulatory requirements and government policy changes.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs, as well costs Hydro One's direct and indirect costs of implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	2018	2019	2020	2021	2022	Plan Period Total	Total Project Costs**
Capital* and Minor Fixed Assets	3.4	5.6	3.9	1.0	-	14.0	19.6
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**3.4**	**5.6**	**3.9**	**1.0**	-	**14.0**	**19.6**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.4**	**5.6**	**3.9**	**1.0**	-	**14.0**	**19.6**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-31 Collection Enhancements

Start Date:	Q1 2022	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	6.1
Primary Trigger:	Financial Performance		
Secondary Trigger:	Customer Focus		

Investment Need:

Overdue accounts present a financial risk to Hydro One. There is a need to improve the collections process and associated technological options for mitigating the financial risks.

The cost of electricity in Ontario has been steadily increasing. This has resulted in a number of customers having difficulty in paying their bills on-time. The Allowance for Doubtful Accounts has increased from 3.8% of its gross accounts receivable (as of December 2013) to 7.3% of its gross accounts receivable (as of December 2015). The portion of net accounts receivables that were aged more than 60 days went from 4% in 2013 to 6% in 2015.

When customers are in arrears, they are contacted by HONI through the Collections "Dunning" process. Dunning is the process of methodically communicating with customers to ensure the collection of accounts receivable. Communications progress from gentle reminders to pointed letters and phone calls to location visits as accounts become in more serious arrears.

One method of enabling customer control of their electricity consumptions, while in arrears condition, and minimizing Hydro One Network's financial risk, is through the use of pre-paid meters. Pre-paid meters are a type of energy meter that requires users to pay for energy before using it. This is done via a smartcard, token or key that can be "topped up" at a corner shop, via a smartphone application or online. For customers who are high collection risk, the financial risk will be minimized by rolling out this type of meter. With a pre-paid meter, electricity is paid up-front. Once the pre-paid amount is used up, power is cut-off until the customer is able to load the meter with more credits.

Alternative 1: Status Quo – No enhancements to Collections Process & Technology. No implementation of pre-paid metering.

With the status quo scenario, Hydro One will not be implementing technology & process changes that are geared towards improving collections such as redesigning the collections process and implementing pre-paid meters.

If Hydro One does not proceed with this project, Hydro One's current increased level of uncollected accounts receivables will continue. This is not preferred since Hydro One's financial performance can be improved if the Company can improve its ability to collect money from its customers. This also does not provide the customer with new technology tools to manage their electricity consumption and reduce their outstanding overdue amounts while in arrears.

Alternative 2: Implement Process & Technology Enhancements for Collections. Roll Out Pre-Paid Meters (Recommended)

With this alternative, Hydro One will implement technology & process changes to encourage customers to promptly pay their bills. Hydro One will be able to implement pre-paid metering which is an effective way to collect payment from its customers. For the rest of the customers who are not high collection risks, the redesigned Dunning process will encourage customers to be prompt in paying their bills. This is the recommended approach as this is expected to increase collections and payment and therefore improve Hydro One's financial performance.

Risk Mitigation:

This is a complex project requiring multiple vendors in order to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class functionality and technology. Hydro One will partner with vendors that have the experience and expertise to complete the work successfully. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

Another risk is potentially the negative customer reaction to the pre-paid meter technology. This risk will be mitigated through proper customer stakeholdering and customer engagement.

The timing of this investment is based on the need to introduce new functionality and technology to encourage collections and payment. Although there is no legislative requirement that is driving this change, delaying this investment any further will result in delayed achievement of benefit which impacts financial performance.

This project has a high degree of complexity; it includes a new technology platform and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

Result:

Collection enhancements will increase likelihood of payment and reduce uncollectable accounts receivables moving forward. Other Canadian and American utilities have successfully implemented this technology and are yielding financial benefits from the deployment.

Outcome Summary:

Customer Focus	• Help customers manage their electricity usage. Active and timely actions to address customers in arrears will help customers stay current with their invoices and will improve payment.
Operational Effectiveness	• Increase operational effectiveness by not having to send field staff to disconnect or reconnect meters for customers who are on pre-paid meter. Meters will automatically shut off once the credit has been consumed on the meter and activate once credit has been loaded.
Public Policy Responsiveness	
Financial Performance	• Encourage customers to be prompt in paying their bills. • Reduce risk of non-payment from high risk customers by through implementing pre-paid meters.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, Vendor cost as well as indirect costs of implementing the solution.

The project is expected to take 2 years to implement. The remaining expenditures relating to this project will be spent in 2023 and are estimated to be $3.0M.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets					6.1	6.1
Less Removals						
Gross Investment Cost					**6.1**	**6.1**
Less Capital Contributions						
Net Investment Cost					**6.1**	**6.1**

**Includes Overhead at current rates.*

GP-32 Customer Data and Analytics

Start Date:	Q1 2018	**Priority:**	High
In-Service Date:	Multiple	**Plan Period Cost ($M):**	9.9
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Customers have told Hydro One that they are concerned about the high cost of electricity. Customers have the right to know and understand what makes up the fees they are being charged.

One way to support customers is through high bill alert functionality. Customers can sign up for e-mail or text messages to alert them if their consumption is trending to exceed a certain threshold that they also are able to set. With high bill alerts, customers may be able to adjust their energy usage and potentially avoid an unusually high bill.

An enhanced web portal provides interactive access to energy-usage information and personalized energy savings recommendations based on usage patterns. By having information available to customers on the website, this reduces the need for customers to call the call centre and the additional effort that comes along with that call.

Equipping Hydro One's Customer Service Agents with tools and systems that provides a comprehensive view of customer information improves the agent's ability to provide good service to customers and get them what they need in a single call. It can be quite frustrating for customers if they call and the Agent they speak with has limited information about the customer's usage and what they can do to reduce their energy bill.

Alternative 1: Status Quo

If the status quo alternative was selected, Hydro One would not be providing customers with the tools they require to effectively manage their electricity account. As such, Hydro One would likely experience deterioration in customer satisfaction, as measured by Hydro One's reputational and transactional surveys.

Alternative 2: Implement Customer Tools and Analytics (Recommended)

This alternative is recommended since it aligns with feedback received from customers via the Distribution Customer Engagement and provides customers with the service they want.

Investment Description:

This investment is required to upgrade the following technology which will enhance customer analytics. The majority of the $9.9 million is allocated to High Bill Alerts.

1. High Bill Alerts - Hydro One will proactively deliver high bill alerts to customers if their bill in a particular billing period is trending higher than a predefined threshold. Customers will also receive guidance on how they can adjust their energy use before the end of the billing period. The alerts are triggered based on the customer's smart meter data combined with historical usage and weather patterns.
2. Enhanced Web Portal for Commercial and Industrial Customers - Hydro One will implement an enhanced web portal for commercial and industrial customers that provides interactive access to energy-usage information and personalized energy savings recommendations based on usage patterns.
3. Customer Analytics and Insights – This investment will allow Hydro One to have a comprehensive view of customer information and will provide analytics and insights, which will allow Hydro One to better understand customer needs and energy patterns.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

<u>Solution Complexity</u>

This investment involves implementation of 3 complex projects. Each project will require multiple vendors to deliver a robust, secure, and cost effective technology platform. As such, a market scan will be conducted to determine best-in-class technology. Hydro One will also engage with customers to solicit input and ensure their needs are met in terms of new features and functionality. With respect to customer privacy and security, market leading security technology will be sought to ensure customer data is well protected.

<u>Resources and Competing Priorities</u>

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

The timing of this investment is based on the need to introduce these customer facing tools to residential, commercial, and industrial customers based on feedback from the Distribution Customer Consultation.

Result:

Overall, this investment caters to diverse customers' needs, thereby improving customer education and customer satisfaction.

High Bill Alerts are expected to reduce average handle times within the call centre for high bill calls and first call resolution will improve. Hydro One expects these initiatives to measurably strengthen Hydro One's relationship with its customers and drive greater credibility and trust.

The Enhanced Web Portal for Commercial and Industrial Customers will deliver energy consumption analysis, building specific insights and savings tips that are personalized for each and every customer – driving awareness, engagement, and action throughout a progressive customer journey. Hydro One seeks to become a trusted advisor by helping customers understand their energy usage.

Outcome Summary:

Customer Focus	• Improve customer service and increase customer satisfaction by providing customers with tools to help manage their energy usage. • Serve customers better by providing Customer Service Agents with tools and resources to enhance call centre operations.
Operational Effectiveness	• Improve efficiency at the call centre by providing Customer Service Agents access to tools and information to better serve customers and reducing average call handling time.
Public Policy Responsiveness	• Encourage energy conservation management by providing consumers the resources to help manage their energy usage.
Financial Performance	• Improve financial performance through more efficient call centre operations and reduction of cost to operate the call centre due to anticipated drop in call volume.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as direct and indirect Hydro One costs for implementing the solution.

This project has a high degree of complexity; it includes redefining the customer experience, a new technology platform, and multiple vendors that require coordination. Given this project is customer facing, thorough testing is required to ensure that the customer experience is positive and security is maintained. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements are finalized and a competitive Request for Proposal (RFP) is initiated and a vendor is selected.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****[**]**
Capital* and Minor Fixed Assets	1.8	-	2.6	5.5	-	9.9	11.7
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	**1.8**	-	**2.6**	**5.5**	-	**9.9**	**11.7**
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**1.8**	-	**2.6**	**5.5**	-	**9.9**	**11.7**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-33 Customer Service Complaint Management Tool

Start Date:	Q4 2017	**Priority:**	Medium
In-Service Date:	Q4 2019	**Plan Period Cost ($M):**	3.3
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One receives approximately 3,000 complaints from customers on an annual basis. Complaints vary in nature but the majority are associated with billing. Customers who log complaints are already experiencing a certain level of frustration. Failing to act promptly and effectively to address the customer's complaint can understandably cause significant additional aggravation.

Currently, complaints are handled on a MS Access database that is not integrated to SAP. As a result, complete and robust customer information is often not available to the staff member handling the complaint and sub-optimal service may result. These databases are not robust enough to contain automatic workflows and related tools to help better serve the customer. Workflows help customer service staff by routing the complaint to the appropriate group(s) that is in the best position to address the customer's complaint. Other customer centric workflows include reminders designed to alert staff if they are lagging on tasks that impact the resolution of a customer's complaint. There are no analytics available to do trending of the root causes of customer's complaints so that the company can handle these issues pro-actively and in turn, reduce the number of complaints going forward.

Alternative 1: Status Quo

If the status quo alternative were selected, Hydro One would continue to use spreadsheets and databases to log customer complaints. This option is not ideal since these spreadsheets and databases are not integrated within Hydro One's SAP system and customer information may not be readily available to assist in addressing the customer's complaint.

Alternative 2: Implement a Dedicated Complaint Management System (Recommended)

This alternative is recommended since the Complaint Management System will be integrated with our SAP Customer Relationship Management. SAP offers a complaint management bundle that enable users to create and store customer complaints about products or services directly in SAP Customer Relationship Management (CRM). Although the decision on whether this will be the tool that will be used has not been determined, this will be the most logical choice given SAP is Hydro One enterprise system. The Complaint Management System will contain workflows to improve productivity. It will document sources, trends, and assist with root cause analyses. As such, it will be utilized to develop a culture of continuous improvement.

Investment Description:
This investment is required to implement an integrated complaint management tool that tracks customer complaints from initiation to resolution. The tool will record and respond to customer complaints and will be fully integrated into Hydro One's SAP Customer Information System (CIS).

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The implementation of the Complaint Management System which is integrated into SAP system is expected to be complex. Finding the right skill set to support a successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Customer Service resources – All of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement a complaint management system that is integrated into SAP. This could potentially pose both process and technology challenges to impacted staff. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. Follow up workshops will be conducted at appropriate project stage gates.

This is a complex project requiring multiple lines-of-business across the company to deliver a robust, secure, and cost effective technology platform. A project governance team will be established and corporate risk workshops will be conducted.

Result:

Customer complaints will be logged in the new Complaint Management Tool. The solution will enable employees to conveniently access the customer's complaint (including previous complaints), account information, and status update. The call center agent will be able to respond to the customer with the latest information on the status of the customers' complaint. This investment will allow Hydro One to manage customer complaints effectively, which in turn improves customer service.

Outcome Summary:

Customer Focus	• Improve customer satisfaction through more efficient and faster handling of customer complaints.
Operational Effectiveness	• Achieve operational efficiencies by identifying trends and root-causes of complaints. • Handle complaints more effectively via built-in task notifications.
Public Policy Responsiveness	
Financial Performance	• Reduce calls to the call centre and the associated effort.

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes vendor costs as well as direct and indirect Hydro One costs.

The cost estimate is based on historical business case estimates of a medium size, complex new SAP module. Until the detailed business requirements and discovery phases are completed and vendor quotes received, a more accurate project cost estimate will not be available.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing & challenging the costs to ensure they are in line. Hydro One will also launch an open competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Plan Period Total**	**Total Project Costs****
Capital* and Minor Fixed Assets	3.0	0.3	-	-	-	3.3	4.1
Less Removals	-	-	-	-	-	0.0	0.0
Gross Investment Cost	3.0	0.3	-	-	-	3.3	4.1
Less Capital Contributions	-	-	-	-	-	0.0	0.0
Net Investment Cost	**3.0**	**0.3**	**-**	**-**	**-**	**3.3**	**4.1**

**Includes overhead at current rates.*
*** Total Project includes amounts spent prior to 2018.*

GP-34 Smart Meter Network Investments

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Multiple	**Plan Period Cost ($M):**	14.7
Primary Trigger:	Customer Focus		
Secondary Trigger:	Operational Effectiveness		

Investment Need:

Hydro One was one of the first LDCs to implement a smart meter network in the province of Ontario. The smart meter project started in 2006 and ended in 2014. This project delivered the advanced meter infrastructure (AMI) in the field and installed approximately 1.2 million smart meters across its customer premises. The CIS billing project started in 2011 and ended in 2014. Its purpose was to replace the legacy billing CSS system in production at that time that was 20 years old and long past its end of life. Both projects were complex and difficult to implement because there was no ubiquitous end to end solution available on the market at the time. The systems had to be “stitched” together using in-house custom development to integrate the smart meter systems, the IESO Meter Data Management and Repository (MDM/R) and the billing systems to create the meter to bill processes that met regulatory requirements set by the Ontario Energy Board.

The Advanced Meter Infrastructure consisted of the Trilliant head end system, collectors and smart meters. The smart meters installation was completed by the 2010 OEB target date. The smart meter communication network was initially completed by 2013 but Hydro One experienced issues in that the network was not providing consistent communications due to factors such as topology, seasonal effects and availability of reliable cellular network services in its rural and remote territory. These constraints required the development of custom applications to handle the exception in the communications network. The smart meter project was concluded in December 2014 once it was determined that there was adequate consistency in the smart meter communications to meet OEB billing accuracy of greater than 98% accuracy.

The 20 year old CSS billing system was replaced with an SAP / Itron IEE solution. The Customer Information System (CIS) project was started in 2011 and implemented in 2013. The synchronization of the CIS with the smart meter network required further customization in order to integrate it with the smart meter systems. The remediation phase of the CIS project concluded in 2014 once it was determined that billing accuracy of greater than 98% could be maintained.

During the smart meter project lifecycle, Hydro One hired consultants to design and implement a number of applications to resolve issues that arose during the integration of the MDM/R. While integrating the Smart Meter network with the SAP CIS billing system additional customized solutions were required to report, track and resolve exceptions. This practice was necessary to create the smart meter to bill processes which was considered new territory for advanced meter infrastructure billing. Today Hydro One continues to operate those customized systems. However, there is both a cost and risks to maintaining this practice because the customized applications are not supported by vendors and they are reaching end of life. Hydro One must rely on very specialized knowledge from a few consultants to maintain these applications that are limited in their scalability and performance. Also costly modifications are required when adding new meter equipment.

Alternative 1: Status Quo

If the status quo alternative was selected, Hydro One would continue to rely on existing technology. This alternative is not recommended since the systems are past their recommended useful life and they are costly to maintain. As such, there is a higher risk of system failure. If the systems were to fail then our customers would receive estimated bills until such time the systems were restored. Furthermore, custom solutions developed internally are no longer consistent with the Company's IT strategy.

Alternative 2: Replace EOL Smart Meter Network tools with new Technology (Recommended)

This alternative is recommended since it will replace end of life technology and reduce the risk of system failure and impact to our 98% billing accuracy performance indicator.

Investment Description:

This investment is required to replace the following tools that support the Smart Meter network. Note that some of the tool replacements or upgrades will be grouped under one or multiple projects depending on the current and future level of integration. Each project will be assessed base on individual business cases that will define the specific costs, return on investments and timeline to implement.

A. Customer Migration Tool - Required to support mass migration of customers from two-tier RPP to Time of Use billing. Hydro One continues to have a number of customers for which a smart meter solution was not available at the time of conversion. This tool will be required to manage the migration of these customers to smart meters.

B. Customer Meter Order Management Tool - Tracks new smart meter installations.

C. Collector Design and Deployment Tool - Coordinates the activities and handoffs for design and deployment of the smart meter network equipment, including regional collectors and repeaters.

D. Customer Service Order Network Tool - Provides reporting for all service orders (planned and unplanned).

E. Index Read Tracking Tool (IRTT) – This tool is the core of the daily meter reading delivery process and serves to provide meter triage, meter reliability metrics, network performance metrics, manual estimation generator, missing read tickets and demand meter reading support.

F. Itron Enterprise Edition Meter Data Management Tool - This tool is an enterprise-wide data management solution that stores interval and register data for residential, commercial, and industrial customers. This tool will have reached end of life and will require an upgrade from the vendor.

G. Network Infrastructure performance reporting – These reports provide the Company's Advanced Meter Infrastructure support team with statistics as to the health of the network.

Risk Mitigation:

This is a complex investment that will require a phased projects approach with multiple vendors in order to deliver a robust, secure, and cost effective technology platform to replace or upgrade the tools listed above. As such, a market scan will be conducted as part of the discovery phase and business case development to determine best-in-class technology and cost to implement.

Result:

The key result is reduction in risk of using meter related customized applications that are not vendor supported. In addition, this is expected to bring efficiencies in the meter-to-bill process through improved reporting & analytics.

Outcome Summary:

Customer Focus	• Improve customer satisfaction as a result of issues being identified quickly and resolved within a timely manner. • Reduce risk to customers in using meter related applications that are no longer supported by the vendor. • Improve operational performance for maintaining billing accuracy.
Operational Effectiveness	• The new technology will result in improved performance.
Public Policy Responsiveness	• Comply with the OEB requirement of 98% billing accuracy.
Financial Performance	

Costs:

This project has a high degree of complexity; it includes a new technology platform and multiple lines of business that require coordination. Given this project is customer facing, thorough testing is required to ensure no impact to the billing process. The cost estimate is based on implementing similar complex applications in the customer domain. Final costs will be determined once detailed business requirements and discovery phases are finalized.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	2.5	6.9	4.0	1.4		14.7
Less Removals						
Gross Investment Cost	2.5	6.9	4.0	1.4		14.7
Less Capital Contributions						
Net Investment Cost	**2.5**	**6.9**	**4.0**	**1.4**		**14.7**

**Includes Overhead at current rates.*

GP-35 Asset Analytics Risk Factor

Start Date:	Q1 2020	**Priority:**	Medium
In-Service Date:	Q4 2020	**Plan Period Cost ($M):**	2.0
Primary Trigger:	Reliability Enhancement		
Secondary Trigger:	Efficiency Improvements		

Investment Need:

Asset Analytics (AA) is a major investment planning decision support toolset. It is an SAP-powered application which represents an enterprise asset risk factor program that consistently measures and models Transmission and Distribution asset risks. The Business has been using the AA program since 2013.

The existing AA program collects asset related information from SAP and other non-SAP interfaces. The data received is used to calculate “Controls” such as Supporting Factors which in turn contribute to the calculation of Risk Factor scores that are used to assess the assets. These controls assist planners identify assets whose status indicates that replacement and/or repair is warranted.

Asset Managers leverage AA output information to make decisions regarding power delivery reliability and supply continuity. Consequently they initiate plans for future capital investments and work programs to improve delivery reliability, customer satisfaction and shareholder value.

Since existing calculations have remained unchanged since the initial deployment of AA, it has been identified by the Asset Managers that current Controls require remediation and extension to improve the quality of the asset risk model, and the granularity for decision making. Specifically required Risk Factor upgrades cover:

a. Adding two new Risk Factors, (Obsolescence and Health, Safety and Environment); and
b. Modifying current Risk Factors with improved data feeds, calculations and reporting.

Alternative 1: Maintaining the Status Quo

- With status quo option, Hydro One can continue to use the AA program with its existing features. This is not to Hydro One's advantage since some of the controls of the existing system require remediation and extension in order to be able to fully realize intended business value and operational efficiencies.

Alternative 2 (Recommended): Implement AA Risk Factor Upgrades

In addition to leveraging the capabilities of the existing AA program, this alternative will lead to realizing the needed business values and operational efficiencies including:

a. Adding two new Risk Factors: The Health, Safety and Environment Risk Factor will contribute to further improving decision data and reducing exposure to employee, public and environmental safety, negative regulatory and media attention. The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment; and
b. Modifying current Risk Factors: This will contribute to improving the quality of the asset risk model as well as the granularity for decision making.

Investment Description:

This investment is to upgrade the Asset Analytics Risk Factors which are used by Investment Planners to support asset maintenance programs and future capital investments planning. The high level scope of the project is expected to be as follows:

a) Add two new Risk Factors. These include:
    - Health, Safety & Environment (HS&E) will incorporate key initiatives around health or environment concerns, such as PCB levels in the insulating oil. Legislation has been enacted that PCB needs to be within certain levels to limit exposure of individuals to the health risk and this investment will support that initiative.
    - Obsolescence will assist with planning the asset useful service life including identification of corrective measure related to equipment defects and availability of spare parts.

b) Modify current Risk Factors with improved calculations and reporting. These include:

- Adding additional Supporting Factors_to algorithms or data feeds to improve the granularity and sensitivity of the Risk Factor scores leading to improved prioritization of assets for work and replacements.
- Adjusting the weighting of Supporting Factors in the algorithms to improve Risk Factor score sensitivity. If an algorithm was not correctly_designed and implemented the first time, correcting it improves the confidence in the Risk Factor scores.

c) Train end users on the operation of the changes in AA.

The recommended execution plan will take approximately 12 months to complete by the fourth quarter of 2020.

Risk Mitigation:

The following are the risks that the project plans to address and manage:

Solution Complexity

The Asset Analytics (AA) Tool a complex application and finding the right skill set support successful implementation can be a challenge. To mitigate this risk, Hydro One will partner with vendors that have the experience and expertise to complete the work successfully.

Resources and Competing Priorities

Hydro One has many demands on its IT infrastructure, SAP and Asset Management – all of which are integral to success of this project. To mitigate this risk, the Project Team will highlight when they expect to require these resources and services during formal Program Planning activities. This will align with priority of projects set by Hydro One's Executive Team as an outcome of the Investment Plan review and approval process.

Change Management and User Adoption

The goal of this project is to implement additional features and capabilities to improve existing processes and transactions. Change Management is a key player to deliver the vision, training and job aids to the target user community wishing to access the new features. This would need to be assessed as to applicability, timing and cost impact.

The above risks will be addressed in accordance with Corporate Projects' Project Governance framework. Following the project approval, the Corporate Risk group will be engaged to conduct a formal risk workshop. In addition, follow up workshops will be conducted at appropriate project stage gates.

Result:

The delivery of the AA Risk Factor Upgrade project will lead to refining the existing risk factor calculations and will help improve quality of investment planning supporting data and in turn the decision quality and results.

The addition of the new Health Safety & Environmental Risk Factor will further improve this decision data and reduce risks to employee, public and environmental safety, and in turn investor confidence and negative regulatory and media attention.

The new Obsolescence Risk Factor will also improve the investment decision data by providing a view to the investment planner of the asset's ongoing sustainability, improving the quality of the investment.

Outcome Summary:

Customer Focus	• Improve customer reliability by providing asset risk data directly to Lines of Business to improve their ability to determine the programs and investments that improve reliability.
Operational Effectiveness	• Upgrades to the AA Risk Factors will ultimately help improve electrical power delivery reliability, supply continuity, data quality, system efficiency and asset investment decision making.
Public Policy Responsiveness	• The outputs from the AA system feed into several information and reports frequently used for regulatory agency reporting (OEB, NERC, IESO, and NEB), government agency reporting (Min of Energy) and customer queries.
Financial Performance	

Costs:

The final cost of the project covers deliverables and support activities such as Design, Infrastructure, Building, Testing, Training, Deployment, Change Management, Project Management and Post Deployment. It includes direct LOB resource cost, vendor cost as well as indirect costs of implementing the solution.

The cost estimate is based on the historical business case estimates of previous AA implementations. Detailed business requirements will be completed during the design phase of the project in order to determine final project costs. If the final project costs are found to be materially different, the project will be re-evaluated given the parameters of the Hydro One investment review and approval processes.

Controllable costs will be minimized by reviewing the detailed cost estimate, when it becomes available, and reviewing and challenging the costs to ensure they are in line.

Hydro One will launch an open bidding competition so multiple vendors can submit their proposal and Hydro One can select based on the vendor that best meets Hydro One's evaluation criteria and budget.

($ Millions)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
Capital* and Minor Fixed Assets	-	-	2.0	-	-	2.0
Less Removals	-	-		-	-	
Gross Investment Cost	-	-	**2.0**	-	-	**2.0**
Less Capital Contributions	-	-	-	-	-	
Net Investment Cost	-	-	**2.0**	-	-	**2.0**

* *Overheads included at current rates*.

TAB 7

CURRICULUM VITAE OF FERIO PUGLIESE

EDUCATION

Western University, Ivey Business School
London, ON (2008)
IEP, Ivey Executive Program - Business

Central Michigan University
Mt. Pleasant, Michigan (1999)
Masters of Arts, Adult Education

University of Windsor
Windsor, ON (1994)
Honours Bachelor of Commerce, Business Administration

University of Windsor
Windsor, ON (1992)
Honours Bachelor of Arts, Communication Studies

INDUSTRY EXPERIENCE

2016 – Present	**Hydro One Networks Inc. / Ontario Hydro**
2016-Present	Executive Vice President, Customer Care and Corporate Affairs
2007 – 2016	**WestJet**
2012-2016	President and EVP WestJet Encore
2007-2012	Executive Vice President, People, Culture and Inflight Services
2003 – 2007	**Catalyst Paper Corporation**
2005-2007	Vice President, Human Resources
2003-2005	Director, Operational Excellence

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD

EB-2017-0049:	**Hydro One Networks Inc. 2018-2022 Distribution Rate Application – Executive Presentation**

TAB 8

CURRICULUM VITAE OF DEREK CHUM

EDUCATION

University of Toronto, Law School
Toronto, ON (2000)
LL.B

University of Toronto
Toronto, ON (1997)
Honours Bachelor of Arts in Political Science

INDUSTRY EXPERIENCE

2017 – Present: **Hydro One Networks Inc.**

Vice President, Indigenous Relations

2010 - 2017 **Amisk Kodim Corporation**

Director, President and Chief Executive Officer

2007 - 2010 **Olthuis Kleer Townshend LLP**

Partner - Corporate/Commercial

APPEARANCE(S) BEFORE THE ONTARIO ENERGY BOARD

N/A

TAB 9

Anwaatin Inc. Interrogatory # 5

Issue:

Issue 6: Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Reference:

A-04-02 Page: 5

Interrogatory:

a) Please identify precisely which of the issues identified Hydro One considers to be beyond Hydro One's authority, jurisdiction and mandate and the rationale for that determination in chart format.

Response:

a) The chart below details provides further information on issues that have been raised by Indigenous communities that are beyond Hydro One's authority, jurisdiction, and mandate as a publicly-traded utility and require or depend upon broader action by the provincial and federal governments.

Issue	Definition	Rationale
Paying for high delivery rates	Will Hydro One address the delivery rates from a Treaty Rights basis which could include entering into resource revenue sharing agreements?	• Hydro One is not responsible for generating electricity in Ontario. It distributes electricity to customers that is generated by Ontario Power Generation and other third-parties. • Like all electricity distributors in Ontario, Hydro One is regulated by the Ontario Energy Board (OEB). As such, Hydro One's delivery rates are based on the cost-to-serve model and are approved by the OEB through a fair, transparent and participatory process. • Any discussion with respect to revenue sharing relating to electricity generated from resources in Ontario should be held between First Nations, the Crown, and other third parties involved in such electricity generation.

Issue	Definition	Rationale
Paying for electricity losses	Why First Nations must pay for electricity lost during transmission, and before it reaches my home or business?	• All electricity customers in Ontario pay for this as it is how rates are designed. • Electricity line losses are an unavoidable part of the electricity distribution business. When electricity is transmitted over long distances and passes through wires and transformers, it is normal for a small amount of power to be used or lost as heat. For example, if we deliver 1,000 kWh to you, we must purchase a small amount more than what you use. To determine the amount of electricity we need to buy for you, we use a calculation called an "adjustment factor."
Compensating for distribution assets	Will Hydro One provide compensation for its distribution assets on reserve? If not why not?	• Hydro One does not provide compensation for distribution assets on reserve, since the distribution facilities serve the First Nation communities, as it does for all of our customers in Ontario. • The only instance where this varies is when a distribution line passes through a First Nation community and out the other side with no "off ramps" to serve the community (often referred to as a sub-transmission line). These are treated like transmission occupations. • Hydro One also does not provide compensation for occupations on road allowances.
Addressing historical grievances	Will Hydro One agree to a process to address historical grievances related to distribution assets on reserve?	• The Ministry of Energy Ontario has agreed to and commenced past grievance process related to energy matters.

Issue	Definition	Rationale
Acquiring proper access rights for assets on reserve	Why are Hydro One distribution assets located on reserve lands without proper rights or with questionable rights acquired many decades ago without proper First Nation's consultation and consent?	• The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued. • Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that Hydro One will manage them until it has obtained permits to complete the title transfer. • To occupy Reserves with transmission assets, Hydro One must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, Hydro One must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights.

TAB 10


HYDRO ONE NETWORKS INC.
TRANSMISSION SYSTEM
& HIGH VOLTAGE STATIONS
- NORTHERN ONTARIO -
hydro one
Treaty 5
Treaty 9
Treaty 3
Robinson - Superior Treaty
Robinson - Huron Treaty
James Bay
Lake Superior
Lake Nipigon
Lake Huron
Georgian Bay
Hydro Assets:
High Voltage Transmission Stations
Stations by Voltage
115 kV
230 kV
500 kV
High Voltage Transmission Lines
Lines by Voltage
115 kV
230 kV
500 kV
First Nations:
First Nations Communities
Remote Communities
Major Cities
First Nations Lands
First Nations Treaty Areas
inergi
Produced By: Inergi LP, GIS Services
Date: February 23, 2011
Map11-24_FirstNations_North
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NOT TO BE REPRODUCED OR REDISTRIBUTED CONFIDENTIAL TO HYDRO ONE NETWORKS INC.
N
W
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100
200
400
km
1:4,000,000
KENORA
THUNDER BAY
FORT FRANCES
TIMMINS
SAULT STE.MARIE
SUDBURY
NORTH BAY
ATTAWAPISKAT
KASHECHEWAN
FORT ALBANY
MOOSONEE SS
FORT HOPE
MARTEN FALLS
WEBEQUIE
SANDY LAKE
DEER LAKE
RED LAKE TS
DRYDEN TS
KENORA TS
MARATHON TS
WAWA TS
HEARST TS
KAPUSKASING TS
PORCUPINE TS
PINARD TS
OTTER RAPIDS SS
LAKEHEAD TS
ALEXANDER SS
PINE PORTAGE SS
MISSISSAGI TS
ESPANOLA TS
HANMER TS
PARRY SOUND TS
MINDEN TS

TAB 11

DEMARCO ALLAN LLP

Lisa (Elisabeth) DeMarco
Senior Partner
5 Hazelton Avenue, Suite 200
Toronto, ON M5R 2E1
TEL +1.647.991.1190
FAX +1.888.734.9459
lisa@demarcoallan.com

May 11, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0049
Hydro One Networks Inc. application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

We are counsel to Anwaatin Inc. (**Anwaatin**) in the above-mentioned proceeding. Please find enclosed the responses from Anwaatin to the interrogatories received from Hydro One Networks Inc. (**HONI**).

Yours very truly,

Lisa (Elisabeth) DeMarco

ANWAATIN RESPONSE TO HONI INTERROGATORY #1

Interrogatory: HONI-01

Preamble: At Exhibit A Tab 4 Schedule 2, Pages 3-4, Hydro One discusses a province-wide First Nations engagement session held in early 2017 and hosted by Hydro One's senior executives. Hydro One's evidence is that all of the 85 First Nation Chiefs from communities served by Hydro One and the Ontario First Nations Regional Organizations were invited to attend this engagement session. Reliability and Partnerships were cited as two of the top 5 concerns identified in this session.

During the Technical Conference (2T166-169) questions were asked by counsel for Anwaatin regarding a further First Nations engagement session that was held on February 21, 2018.

Hydro One is interested in Dr. Richardson's understanding of these engagement sessions and how these sessions have informed the views expressed in his evidence.

Question: 1. Please confirm Dr. Richardson was aware that First Nation members of Anwaatin attended the referenced 2017 and 2018 First Nation engagement sessions. If so, please indicate which First Nations attended either on their own behalf or on behalf of Anwaatin.

2. In preparing his evidence, what steps did Dr. Richardson take to understand why specific issues concerning investments in distributed energy resources were not raised at these sessions by First Nations attended either on their own behalf or on behalf of Anwaatin? Is Dr. Richardson aware of any reasons that precluded such matters from being raised? Alternatively, if Dr. Richardson is of the view that such matters were raised, please provide all materials presented and a summary of such discussions.

Response: 1. Dr. Richardson was aware that First Nation members of Anwaatin Inc. attended the 2017 HONI engagement session and were not satisfied that HONI was taking prompt actions to address the reliability disparity and very significant negative impacts of poor reliability in their communities. Dr. Richardson was then engaged by Anwaatin to research and develop potential solutions that could be promptly and efficiently implemented to address the reliability crisis in the Anwaatin First Nation communities. After the filing of the HONI EB-2017-0049 Application, both Larry Sault, CEO of Anwaatin, representing Anwaatin First Nation members, as well as Anwaatin First Nations members attended the HONI 2018 engagement session. Mr. Sault hand-delivered and distributed the following written comments and questions to HONI representatives at the 2018 engagement session:

i) *Poor system reliability and disproportionate negative impact on First Nations with Hydro One*

   - *There is an extraordinary and very real reliability disparity that First Nations communities are experiencing and have been experiencing for a long time - the disproportionate negative impact that that reliability disparity has specifically on First Nations communities.*
   - *Evidence shows that 60% of distribution assets serving First Nation communities are CDPP outliers (Customer Deliver Point Performance Standard "outliners" are the worst performing parts of the transmission system)*
   - *Delivery point reliability for A4L transmission line communities – Lake Nipigon First Nations to Geraldton/Ginoogaming/Aroland is 20.81 times worse than Ontario average - Four times worse than other Northern Ontario communities*

ii) *First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.*

iii) *Distributed Energy Resources (DERS) - North America's electric power system generation resource mix is changing from the use of larger synchronous sources to the use of a* *more diverse fleet of smaller sized resources with varying generation characteristics called Distributed Energy Resources or DERS which include renewables, energy storage and biomass generation*

- *How is Hydro One creating First Nations investment/ownership opportunities, and other business partnership opportunities related to DERs in grid-connected communities?*
- *How is Hydro One working with First Nations on DERs to improve system reliability given the very poor reliability of systems serving First Nations?*
- *Given Hydro One's findings that some First Nation communities indicate that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve, does Hydro One have plans to integrate DERs into areas of Northern Ontario that experience high frequency and duration of power outages to improve reliability? If such plans exist, please provide them.*
- *Has Hydro One considered approaches to DERs and business partnerships with DERs, as potential accommodation for First Nation communities concerned about compensation, or the lack thereof, for Hydro One transmission and distribution assets on reserve land and off reserve but within traditional territories and treaty lands?*
- *How does Hydro One's investment planning process consider appropriate planning criteria for the increasing scale of demand for DERs, especially for rural and First Nation customers seeking relief from reliability issues and increasing costs?*

2. Please see response to HONI-01(1).

ANWAATIN RESPONSE TO HONI INTERROGATORY #2

Interrogatory: HONI-02

Preamble: On September 7, 2017, OEB Staff prepared and filed in this proceeding a Community Engagement Report outlining the results of several engagement sessions undertaken with Hydro One customers affected by the 2018-2022 Hydro One Distribution Rates Application

Hydro One is interested in understanding how this information was taken into account by Dr. Richardson in preparing his evidence.

Question: 1. Which OEB Community Engagement Sessions were attended by Anwaatin Inc. representatives? In your response, please refer to the specific presentations described in the Community Engagement Report and where (1) matters relating to distributed energy resources were raised as issues of concern or topics of interest; or (2) the lack of consultation Hydro One had carried out with Anwaatin Inc. or its representatives prior to filing its 2018-2022 Distribution Rates Application.

2. If no presentations were made by Anwaatin Inc. or its representatives at any of these sessions, please provide Dr. Richardson's understanding why concerns regarding the lack of Hydro One's consultation with First Nations and other communities regarding distributed energy resources were not raised at that time?

3. Please provide all correspondence made prior to the filing of this Application between Anwaatin Inc. or its representatives to Hydro One and which evidence Anwaatin Inc. specific interest in the use of distributed energy resources and the need for Hydro One to address such matters in its 2018 Distribution Rates Application.

Response: 1. Please see Anwaatin's response to HONI-01.

2. Please see Anwaatin's response to HONI-01.

3. Please see Anwaatin's response to HONI-01 and the May 3, 2018 joint letter of HONI and Anwaatin to the Ontario Energy Board (attached as Appendix A to this response) for communications that are not subject to settlement privilege.

Appendix 'A' to Anwaatin Response to HONI IR #2 (3)

May 3, 2018

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: EB-2017-0335
Anwaatin Inc. Motion to Review and Vary Ontario Energy Board Decision in EB-2016-0160 ("Anwaatin MRV")

This letter is provided by, and on behalf of, Anwaatin Inc. (**Anwaatin**) and Hydro One Networks Inc. (**HONI**) in relation to the Anwaatin MRV. We wish to advise the Board that Anwaatin and HONI are in the process of negotiating a potential solution to the reliability disparity issues that have characterized the A4L transmission line and challenged the First Nations communities that are served by it.

We hope to provide the Board and the two intervenors on the Anwaatin MRV with further information and developments on or before May 18, 2018, and would therefore ask that the Board refrain from issuing its Decision on the Anwaatin MRV until after that date in order to allow the Parties to continue their constructive dialogue.

Sincerely,

Lisa (Elisabeth) DeMarco
Senior Partner
DeMarco Allan LLP

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Toronto, ON M5R 2E1
TEL +1.647.991.1190

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Toronto, Ontario M5G 2P5

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lisa@demarcoallan.com

www.HydroOne.com

ANWAATIN RESPONSE TO HONI INTERROGATORY #3

Interrogatory: HONI-03

Preamble: On March 1, 2018 the Ontario Energy Board convened a Technical Conference into the 2018-2022 Hydro One Distribution Rates Application. In response to follow-up questions from Anwaatin counsel regarding Exhibit I Tab 6 Schedule 1 (Response to Anwaatin Interrogatory #1), Hydro One provided greater detail regarding recent efforts undertaken to explore opportunities to partner with interested First Nations and to leverage federal and provincial government funding to support green energy and greenhouse gas reducing energy projects.

At Transcript Volume 2 pages 152-162, Hydro One's witnesses indicated that initiatives underway with distributed energy resources involving a First Nation situated on Christian Island had only just commenced in 2017 following the filing of this Application. Additionally, that discussions with Anwaatin First Nation members affected by circuit A4L had commenced at the beginning of 2018 (i.e. prior to the interrogatory process in this proceeding) and were ongoing.

Hydro One is interested in Dr. Richardson's awareness of this information when preparing his evidence and how this evidence is intended to (a) influence the conduct of ongoing commercial discussions between Hydro One and Anwaatin regarding distributed energy resources and (b) the timing of Hydro One's current capital plan that includes replacement of the A4L circuit during the rate period.

Question: 1. When did Dr. Richardson become aware of and review the Technical Conference evidence?

2. What consideration was given by Dr. Richardson to the Technical Conference evidence in formulating his conclusions/assertions made

regarding inadequate consultation by Hydro One with respect to distributed energy resources?

3. Is it Dr. Richardson's view that Hydro One's proposed replacement of the A4L circuit should be deferred until commercial arrangements regarding a possible joint venture arrangement between Hydro One, Anwaatin Inc., and potentially others is concluded?

4. Acknowledging Dr. Richardson's lack of expertise, does Dr. Richardson believe the Ontario Energy Board should direct Hydro One to rely on a distributed energy resource solution in place of A4L replacement without first evaluating the cost and reliability differences between wire and non-wire solutions? Should activities regarding replacement of the A4L circuit be deferred until such cost and reliability comparisons are completed ad commercial joint ventures, if any, reached?

5. Is it Dr. Richardson's belief that such a point of cost and reliability comparison between replacing the A4L circuit vs relying on a distributed energy resource solution has been reached? If so, please provide all analysis that Dr. Richardson has conducted demonstrating that a distributed energy resource solution provides for greater reliability and lower cost as compared to Hydro One's current plan to replace the A4L circuit.

Response: 1. Dr. Richardson was engaged and aware of the Technical Conference evidence provided by Hydro One, and particularly the portions of the Technical Conference outlined in Transcript Volume 2 from page 155, line 22 to page 157 line 23 (reproduced below) wherein Hydro One witnesses indicate that they had yet to engage with the First Nations communities in relation to the two projects that Hydro One was contemplating without specific outcome, commitment, or timeline.

> MR. FERGUSON: Thank you. Can you tell us which First Nations you're exploring these opportunities with? And if you can't do it off the top of your head could you undertake to provide the First Nations?
> MR. JESUS: You mentioned Christian Island.
> MS. GARZOUZI: Yeah, Christian Island is the one example—
> MR. FERGUSON: Are there other –

MS. GARZOUZI: -- that I'm familiar with.
MR. FERGUSON: Are there other examples?
MS. GARZOUZI: I don't believe so.
MR. FERGUSON: Believe so?
MS. GARZOUZI: Just a moment --
MR. NETTLETON: Ms. Garzouzi, would you mind just speaking closer to the mic?
MS. GARZOUZI: Sure.
MR. JESUS: I'll take that. So the other one that we are exploring is the A4L transmission circuit to the Anwaatin communities that supply to the Moosonee DS, so we are looking at that opportunity as well.
MR. FERGUSON: And can you expand on that, and how are you looking at that --
MR. JESUS: Well, from a --
MR. FERGUSON: -- opportunity?
MR. JESUS: -- from a -- from a transmission point of view we're looking at the reliability of supply. From a distribution point of view we're looking at the reliability of supply and seeing how it compares with the rest of the feeders in the province, as part of the worst performing feeders, and seeing what we can actually do in that community.
MR. FERGUSON: That's great. And how far along with that work are you? How much -- what have you done and what's the timeline?
MR. JESUS: So we're just starting to explore that particular project --
MR. FERGUSON: Mm-hmm.
MR. JESUS: -- and we expect it to get further along by the course of the year.
MR. FERGUSON: And what do you mean by "get further along", just for clarity?
MR. JESUS: So we're moving that project forward. We're looking to move it forward.
MR. FERGUSON: And where would you like to be by the end of -- where is the plan to be by the end of the year?
MR. JESUS: So right now we haven't got a full schedule for that --
MR. FERGUSON: Okay.
MR. JESUS: -- to be totally honest. I think at the end of the day we're exploring it and it is -- it's one of the communities that we're looking at --
MR. FERGUSON: And have you been --
MR. JESUS: -- is Christian Island.
MR. FERGUSON: And you've been engaging with and working with the communities on this?
MR. JESUS: We have not started that yet.
MR. FERGUSON: You have not started that yet?
MR. JESUS: No.

Dr. Richardson is now aware of further privileged discussions between HONI and Anwaatin as referenced in HONI-02(3) Appendix A.

2. Please see response to HONI-03(1) and specifically the HONI evidence (Technical Conference, Tr. Vol.2, line 19-23) that HONI had not yet engaged with the specific First Nations Communities:

MR. FERGUSON: And you've been engaging with and

> working with the communities on this?
> MR. JESUS: We have not started that yet.
> MR. FERGUSON: You have not started that yet?
> MR. JESUS: No.

3. Dr. Richardson is of the current understanding, subject to further developments and cooperative action, that Hydro One has not proposed prompt replacement of the A4L in a manner and on a timeline that resolves the immediate and ongoing reliability crisis in the Greenstone-Marathon and Anwaatin First Nations communities. In contrast and in accordance with Ex. B1-1-1, Section 1.2, Attachment 14, at page 37 of 77 (or p.824 of 2850), Anwaatin understood that the recommended stage 2 was contingent and undertaken to accommodate a gas to oil pipeline conversion project (Energy East), which has since been cancelled by the proponent.

Similarly, the conclusions and implementation of the IRPP (p.857 of 2076) do not appear to be committing to prompt A4L line replacement.

Dr. Richardson generally supports solutions that result in prompt and measureable improvement to reliability in the Anwaatin First Nations communities and allow for economic growth in the North of Dryden, Greenstone-Marathon, and West of Thunder Bay Regional Planning Areas.

4. Anwaatin does not acknowledge and agree with the pretense of this question. Please refer to HONI-02(3) Appendix A.

5. Dr. Richardson is of the view that the cost and reliability of short, medium and long term staged and/or phased implementation of immediate solutions, including DERs, to address reliability in each and all of the Greenstone – Marathon, Nipigon, North of Dryden areas is relevant. Please refer to HONI.2(3) Appendix A.

ANWAATIN RESPONSE TO HONI INTERROGATORY #4

Interrogatory: HONI-04

Preamble: At paragraphs 14-16 of Dr. Richardson's evidence, criticism is provided regarding Hydro One's three-pronged strategy to improve system reliability in First Nation Communities. Dr. Richardson's evidence continues to discuss the merits of non-wire solutions as another way in which system reliability can be improved and at potentially lower costs than wire solutions.

At the Technical Conference, Hydro One's witnesses explained that distributed energy resource solutions were being considered, however such efforts had only begun and were in the preliminary stages and such efforts followed the filing of the Application.

Dr. Richardson refers to an IESO Report dated December 16, 2016 discussing community energy plans in First Nation communities in the Parry Sound/Muskoka area and cites the conclusions that more research is needed to understand the cost and feasibility of using DERs.

Question: 1. Is it Dr. Richardson's view that none of the three-prongs to the stated strategy can consider non-wires solutions when, for example, capital investment decisions are made (prong 1) or when new technologies emerge (prong 2) or using such solutions when bundling work (prong 3)? Please fully explain why such approaches (consideration of non-wire solutions within the three stated prongs of the strategy) are not possible, acknowledging Dr. Richardson is not an expert in such matters.

2. Is it Dr. Richardson's view that as of today's date, sufficient research and understanding now exists regarding the cost and feasibility of using DERs. If so, please provide the information Dr. Richardson is relying on published after the IESO's conclusion dated December 16, 2016 and today.

3. If Dr. Richardson is not challenging the IESO's December 16, 2016 conclusion, does Dr. Richardson take exception to the approach Hydro One is currently following, as explained during the Technical Conference, of proceeding with the use of pilot projects to further the understanding of how DER's may improve system reliability and the costs associated with such potential solutions. If so, please fully explain.

Response: 1. Dr. Richardson has not provided expert evidence in this proceeding and has been engaged to assist HONI's most vulnerable First Nations customers to develop immediate reliability solutions to HONI's extreme reliability disparity issues in the Anwaatin communities. It is Dr. Richardson's view is that, in its current level of elaboration, none of the elements of HONI's three-pronged strategy intended to increase system reliability ***within First Nations communities*** appropriately addresses the role of DERs and other non-wires solutions, which may be particularly well-suited to Indigenous communities.

2. Dr. Richardson's view, which he believes to be shared by honi experts, is that sufficient research and understanding now exists regarding the cost and feasibility of using ders in order for honi to make specific effort to consider these approaches as part of short, medium and long term capital investment and reliability improvement decisions in this and future proceedings. Please see HONI-02(3) Appendix A.

3. Dr. Richardson supports Hydro One's current approach to proceeding with the use of pilot projects that benefit First Nations that suffer from reliability disparity issues and disproportionately negative impacts from poor electricity reliability. Dr. Richardson recommends that Hydro One consider BOTH wires and non-wires alternatives as potential solutions to address and resolve reliability challenges in a cost efficient and appropriately staged manner.

ANWAATIN RESPONSE TO HONI INTERROGATORY #5

Interrogatory: HONI-05

Preamble: Dr. Richardson refers to several documents prepared by the Ontario Independent Electricity System Operator ("IESO") which have considered the topic of distributed energy resources.

At Exhibit B1-1-1 Section 1.2 Hydro One discusses the regional planning process used in the Province and which is coordinated by the IESO. At page 4 of 25 of this Exhibit, Hydro One references the fact that emergent needs brought forward by the transmitter, distributors, customers or the IESO that cannot wait until the next scheduled plan is developed is one such "planning trigger". Reference is further made to the steps that the IESO may take (i.e. initiating a Scoping Assessment process) in collaboration with distributors and transmitters in its consideration of non-wires solutions to address the needs in a region or sub-region.

Hydro One is interested in how Dr. Richardson has taken into account the IESO's regional planning process and his views on whether this planning process would best address emerging technologies and approaches such as distributed energy resources as described in his evidence.

Question: 1. When preparing his evidence, what consideration was given by Dr. Richardson to the IESO's regional planning process and specifically, the opportunity for customers to provide input into this planning process for emerging needs and solutions that include non-wire approaches?

2. Is Dr. Richardson aware of any steps taken by Anwaatin or its representatives to discuss distributed energy resources as potential non-wire solutions with the IESO? If so, please summarize these discussions, provide a chronology of when such discussion took place and discuss any next steps that are planned.

3. Is Dr. Richardson in a position to comment on any concerns or issues that the IESO has identified that require additional study before distributed energy resources are ones that could be adopted in the Anwaatin planning region?

Response: 1. Dr. Richardson reviewed the IESO's regional planning reports in the context of the EB-2017-0049 application and the evidence prepared by Dr. Richardson for Anwaatin. He notes that the IESO regional planning reports included at B1-1-1, Section 1.2 attachments 13-15 inclusive, refer to consultation with First Nations and Indigenous communities in the North of Dryden, Greenstone- Marathon, and West of Thunder Bay, that took place largely between 2013 and 2015, prior to Dr. Richardson's engagement and any Anwaatin intervention in OEB proceedings in attempt to promptly address the reliability disparity crisis and disproportionate negative impacts of poor reliability on the Anwaatin First Nation communities.

2. Please see HONI-02(3) Appendix A.

3. Dr. Richardson is not aware of any specific IESO concerns or issues with respect to the HONI A4L distribution systems or the HONI Moosonee distribution systems with respect to the adoption of distributed energy resources.

In May, 2016, the IESO reported on its "high-level assessment" of Renewable Distributed Generation for the Greenstone-Marathon Sub-region to meet capacity needs, which at the time included a proposed 100 MW for pumping station for a gas converted to oil pipeline and the proposed Geraldton mine which will require in excess of the 25 MW of capacity. Since that time, the proposed oil pipeline has been cancelled and the Greenstone mine has formally filed federal and provincial environmental assessments that include a DER in the form of a non-grid connected combined heat and power plant with a generating capacity of approximately 48.5 megawatts.

The IESO did not facilitate an Integrated Regional Resource Plan with respect to the North/East Sudbury region. Instead, HONI provided a North/East Sudbury Regional Infrastructure Plan ("RIP") in April

2017.[1] The North/East Sudbury RIP makes no references to DERs, and is specifically a "wires-only" options report, does not reference First Nation consultation, and was not distributed to First Nations.

[1] HONI, 2017. North/East Sudbury Regional Infrastructure Plan. Available online at: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/northeastofsudbury/Documents/Regional%20Infrastructure%20Plan_North-East%20of%20Sudbury.pdf

ANWAATIN RESPONSE TO HONI INTERROGATORY #6

Interrogatory: **HONI-06**

Preamble: On its website (http://www.ieso.ca/en/get-involved/regional-planning/northwest-ontario/overview) the IESO reports that the single regional planning area for Northwest Ontario has been divided into four planning sub-regions. The IESO further reports that individual plans are being prepared for each sub-area and will be integrated into an overall Northwest regional plan. Community engagement is stated to be an important part of the regional planning process and sometimes includes the development of a Local Advisory Committee (LAC), which has up to 18 members, representing municipalities, First Nation and Metis communities, consumers and citizens, the business community, and environmental conservation groups.

Active engagements in Northwest Ontario are reported to have taken place regarding the sub-region of Greenstone-Marathon and an Integrated Regional Resource Plan was completed in June 2016.

Hydro One is interested in how Dr. Richardson has considered the IESO's regional planning process as a means for Anwaatin or its First Nation members to give consideration to potential reliability improvement solutions involving new technologies that may be associated with distributed energy resources.

Question: 1. Was Dr. Richardson aware of the engagement process associated with the development of the IESO Greenstone-Marathon Integrated Regional Resource Plan at the time his evidence was prepared?

2. Please provide Dr. Richardson's understanding of the IESO's ongoing engagement sessions that have been held in the Northwest Ontario region subsequent to the release of the Greenstone-Marathon Integrated Regional Resource Plan. In your response, please indicate whether Anwaatin or representatives from its First

Nation members attended these engagement sessions and the dates such engagement sessions were held. Please also address whether issues related to distributed energy resources were raised at such meetings.

Response: 1. Please see response to HONI-05(1).

2. Please see response to HONI-05(1). Further, Dr. Richardson understands that those sessions were primarily focused on prospective electricity load demands for a proposed large oil pipeline and a proposed mine. The oil pipeline project was cancelled in Fall, 2017, and the mining project is proceeding with regulatory approvals for a DER (self-generation). Both events fundamentally alter the IESO demand assumptions and resource conclusions in the report.