**EB-2019-0082**

**ONTARIO ENERGY BOARD**

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

**AND IN THE MATTER OF** an Application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the *Ontario Energy Board Act*, *1998* approving rates for the transmission of electricity.

.

---

**COMPENDIUM OF THE SCHOOL ENERGY COALITION**
**(Panel 1 – Asset Management, Planning & Work Execution)**

---


**Shepherd Rubenstein P.C.**
2200 Yonge Street, Suite 1302
Toronto, Ontario M4S 2C6

**Mark Rubenstein**

Tel: 416-483-3300
Fax: 416-483-3305

**Counsel for the School Energy Coalition**

**Table 1 - Historical Capital Expenditure Summary**

| OEB Category | Historical (Previous Plan and Actual) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | | | 2016 | | | 2017 | | | 2018 | | |
| | Actual | Plan | Var | Actual | Plan | Var | Actual | Plan | Var | Actual | Plan | Var |
| | $M | $M | % | $M | $M | % | $M | $M | % | $M | $M | % |
| **System Access** | 7.6 | 19.7 | -61% | 17.0 | 31.9 | -47% | 42.7 | 33.3 | 28% | 33.7 | 24.3 | 39% |
| **System Renewal** | 688.9 | 573.6 | 20% | 733.9 | 539.9 | 36% | 740.7 | 733.7 | 1% | 776.2 | 780.4 | -1% |
| **System Service** | 157.9 | 189.9 | -17% | 140.9 | 180.0 | -22% | 93.5 | 97.0 | -4% | 73.9 | 75.6 | -2% |
| **General Plant** | 88.6 | 116.3 | -24% | 94.8 | 114.6 | -17% | 76.9 | 86.0 | -11% | 83.6 | 119.7 | -30% |
| **Total** | **943.0** | **899.4** | **5%** | **986.7** | **866.3** | **14%** | **953.9** | **950.0** | 0% | **967.3** | **1,000.0** | -3% |
| **System OM&A[1]** | 441.6 | 431.2 | 2% | 408.1 | 436.8 | -7% | 385.0 | 397.7 | -3% | 419.2 | 394.3 | 6% |

[1] System OM&A includes Operations, Maintenance and Administration expenses. System OM&A for 2021 to 2022 is determined based on the Revenue Cap Index identified in Exhibit A, Tab 4, Schedule 1.

**Table 2 - Bridge Year and Test Year Capital Expenditure Summary**

| OEB Category | Bridge | Forecast | | | | |
|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| | F/Cast | Test | Test | Test | Plan | Plan |
| | $M | $M | $M | $M | $M | $M |
| **System Access** | 45.1 | 24.8 | 11.3 | 11.7 | 12.7 | 4.1 |
| **System Renewal** | 773.3 | 865.2 | 1,103.1 | 1,172.8 | 1,177.4 | 1,193.8 |
| **System Service** | 103.8 | 204.1 | 148.2 | 151.8 | 174.3 | 204.2 |
| **General Plant** | 116.3 | 115.4 | 94.4 | 94.7 | 83.6 | 58.9 |
| **Progressive Productivity Placeholder** | 0.0 | -17.0 | -39.0 | -61.0 | -78.0 | -91.0 |
| **Directive[2]** | **-0.3** | **-0.3** | **-0.3** | **-0.4** | **-0.4** | **-0.4** |
| **Total** | **1,038.2** | **1,192.2** | **1,317.7** | **1,369.6** | **1,369.6** | **1,369.6** |
| **System OM&A[1,3]** | **356.5** | **375.8** | * | * | **N/A** | **N/A** |

For explanatory notes on Forecast Trends vs. Historical Budgets by Category, please see Section 3.3.2.

For explanatory notes on Plan vs. Actual Variance Trends by Category, please see Section 3.3.3.

For explanatory notes on System OM&A, please see Exhibit F.

---

[2] The Directive adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

[3] Includes the Directive adjustment. Refer to Exhibit F, Tab 1, Schedule 1 for further details.

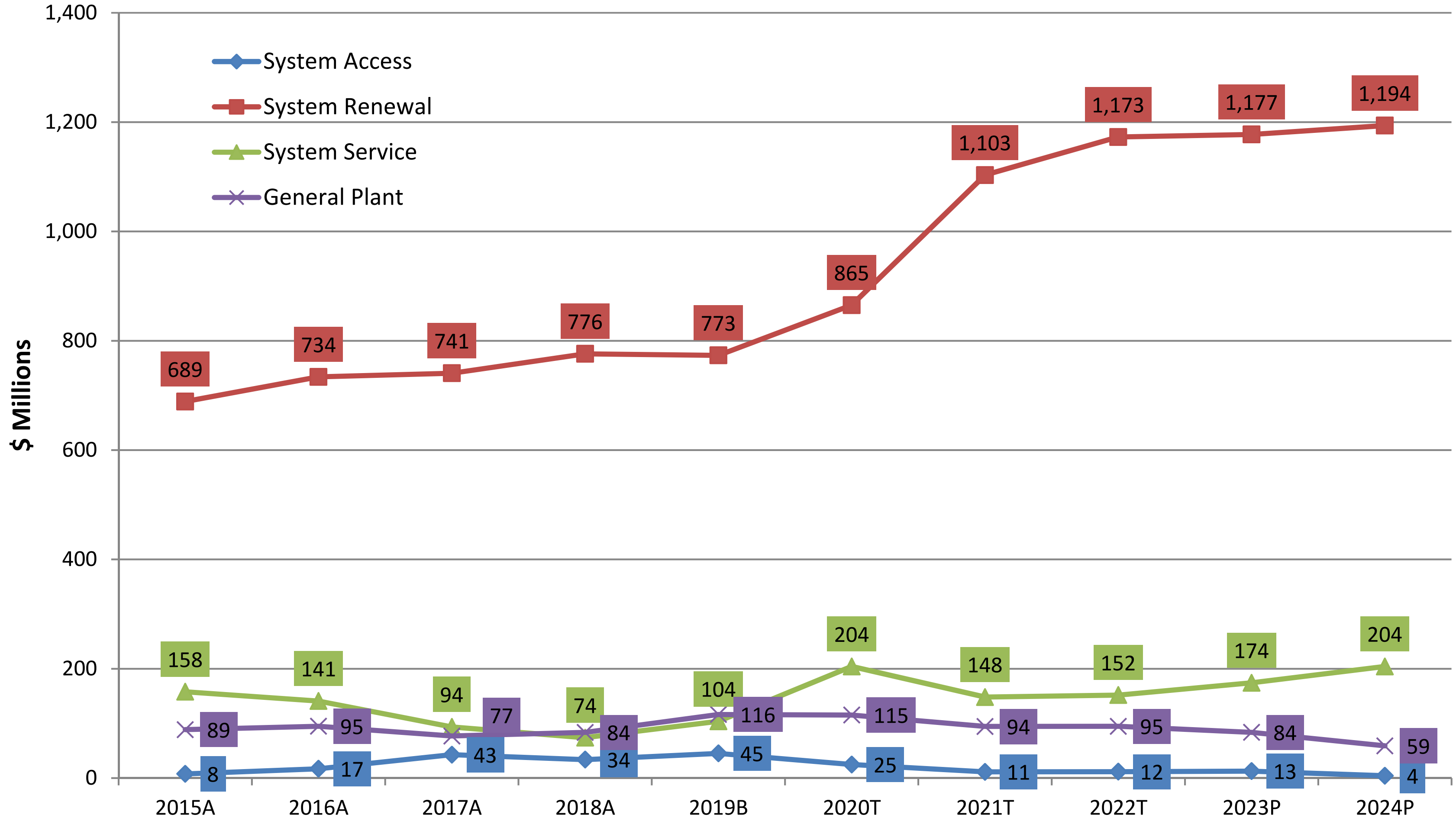



**Figure 1 - Actual / Forecast Capital Expenditures 2015 - 2024 by Category**

**(A=Actual, B=Bridge Forecast, T=Test Forecast, P=Plan)**

Witness: Donna Jablonsky/Robert Reinmuller/Rob Berardi/Lincoln Frost-Hunt

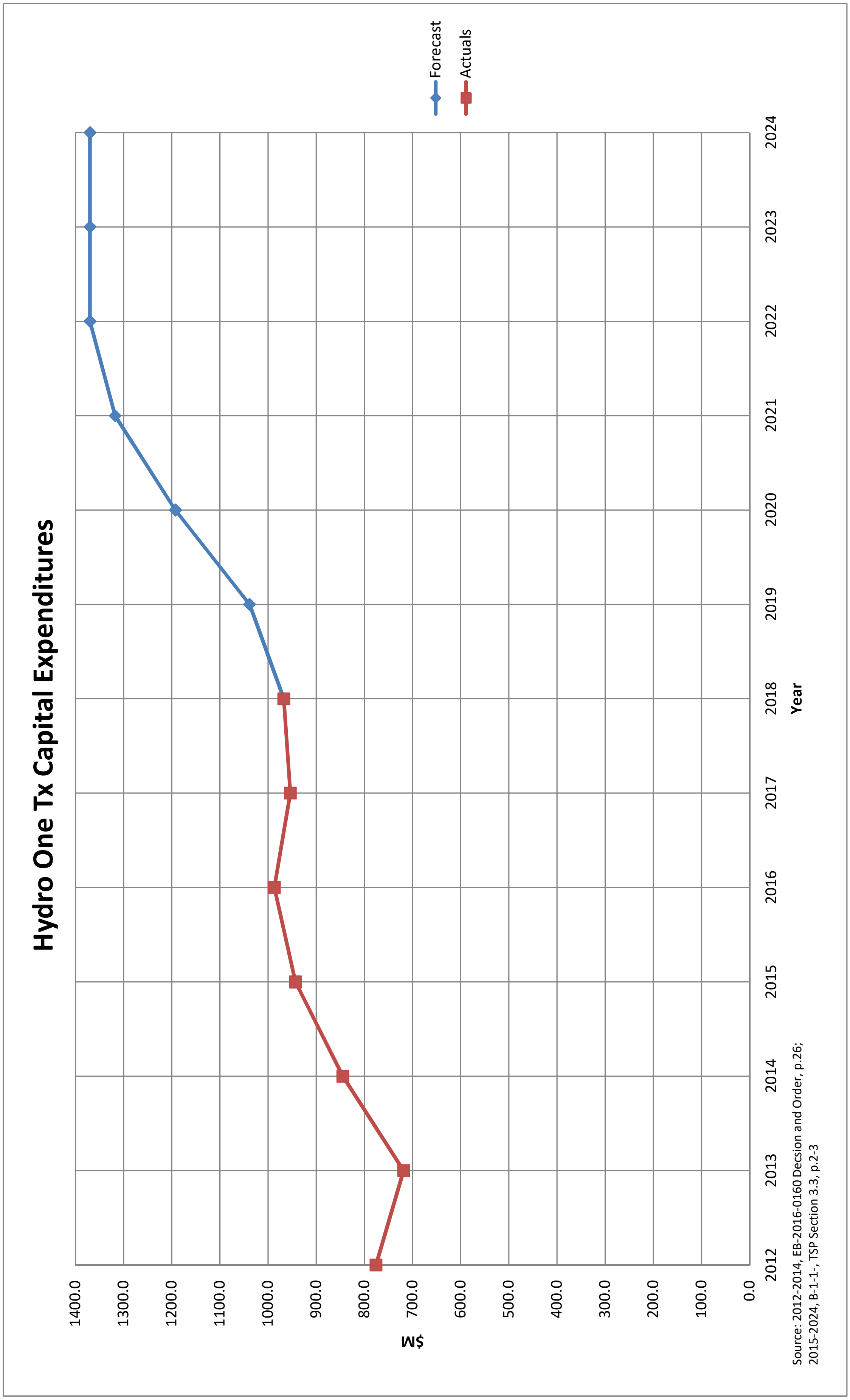

Hydro One Tx Capital Expenditures
$M
1400.0
1300.0
1200.0
1100.0
1000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
Forecast
Actuals
Source: 2012-2014, EB-2016-0160 Decsion and Order, p.26;
2015-2024, B-1-1-, TSP Section 3.3, p.2-3

**Table 1: In-Service Capital Additions 2014 – 2022 ($ millions)**

| | Historical | | | | | | | | | | | | | | | | | Bridge | Test | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014 | | | 2015 | | | 2016 | | | | | 2017 | | | 2018 | | | | | | |
| | Actual | Plan | Variance | Actual | Plan | Variance | Actual | New Plan [1] | Plan | Variance (New Plan) | Variance (Plan) | Actual | Plan | Variance | Actual | Plan | Variance | 2019 | 2020 | 2021 | 2022 |
| System Access | 34.1 | 50.4 | -32% | 8.9 | 13.9 | -36% | 10.1 | 17.7 | 3.0 | -43% | 237% | 51.2 | 1.8 | 2,744% | 12.1 | 68.2 | -82% | 30.4 | 59.2 | 5.3 | 14.1 |
| System Renewal | 649.6 | 575.8 | 13% | 559.8 | 563.3 | -1% | 635.7 | 595.4 | 472.0 | 7% | 35% | 657.8 | 717.0 | -8% | 852.3 | 761.4 | 12% | 770.5 | 762.0 | 998.7 | 1,138.7 |
| System Service | 144.8 | 129.9 | 11% | 18.7 | 120.7 | -85% | 174.2 | 192.4 | 116.6 | -9% | 49% | 85.7 | 70.4 | 22% | 218.0 | 244.8 | -11% | 54.5 | 155.1 | 175.2 | 137.7 |
| General Plant | 86.0 | 107.2 | -20% | 111.7 | 123.4 | -9% | 90.2 | 106.3 | 81.7 | -15% | 10% | 77.5 | 78.5 | -1% | 77.9 | 104.0 | -25% | 95.6 | 76.9 | 155.1 | 59.5 |
| Progressive Productivity Placeholder | | | | | | | | | | | | | | | | | | | (15.8) | (36.3) | (56.7) |
| **Total** | **914.5** | **863.3** | **6%** | **699.1** | **821.3** | **-15%** | **910.2** | **911.7** | **673.3** | **-0.2%** | **35%** | **872.2** | **867.7** | **1%** | **1,160.4** | **1,178.4** | **-2%** | **951.0** | **1,037.4** | **1,298.0** | **1,293.3** |
| Directive* | | | | | | | | | | | | | | | | | | -0.3 | -0.3 | -0.3 | -0.4 |
| **Total** | | | | | | | | | | | | | | | | | | **950.7** | **1,037.1** | **1,297.7** | **1,293.0** |

[1] *New Plan represents the 2016 Bridge Year forecast from 2017-2018 Transmission Rate Application (EB-2016-0160)*

* Directive refers to the Government Directive on compensation as detailed and defined in Exhibit F, Tab 4, Schedule 1.

# 2019-2024
# Transmission Business Plan

December 14, 2018

PURPOSE-LED
VALUES DRIVEN
hydro one

SAFETY COMES FIRST | STAND FOR PEOPLE | EMPOWERED TO ACT | OPTIMISM CHARGES US | WIN AS ONE

# Customer Focus

## Customer Needs and Preferences

For the Plan, Hydro One continued to leverage the comprehensive customer engagement work completed in the spring of 2017 along with its ongoing regular customer interaction. Based on the information collected during these processes, the following customer needs and preferences were identified:

- Customer priorities are as follows: safety, reliability, outage restoration, power quality, customer service, productivity and environmental stewardship.
- All business customer segments, particularly Local Distribution Companies (LDCs), prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for customers and the ability to plan ahead.
- Reducing the frequency of power interruptions is more important than reducing the duration. Most important is reducing the number of day-to-day interruptions.
- When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in Hydro One's 2017-2018 transmission rate application[1] by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option.

The Transmission Investment Plan for the period 2019-2024 incorporates the results of the customer engagement process, within the confines of the proposed constrained OM&A budget, while balancing system/asset needs, and risk mitigation in the following ways:

- As best able, optimizes the life of the existing assets while mitigating the risk to safety and to current service levels posed by asset deterioration;
- System and customer reliability are maintained amongst the company's peers for reliability performance;
- Addresses customer needs and preferences through new customer connections, and regional development to enable growth and system renewal to meet current requirements;
- Responds to customer power quality concerns by proactively monitoring power quality across the province and working with customers to resolve specific issues; and

[1] Proposed capital budgets were $1076 million for 2017 and $1122 million for 2018. The OEB ultimately approved capital envelopes of $950 million for 2017 and $1000 million for 2018.

- Incorporates increased cost reductions and productivity improvements totaling $785 million resulting in lower revenue requirement of $64 million (3.13%) by 2024 to offset the customer rate impacts of the proposed investment plan.

## Impact of the Plan on Customer Rates and Bills

On March 16, 2018, the OEB advised Hydro One that rates for the distribution and transmission businesses should be considered in a single application. To facilitate this outcome, the OEB asked Hydro One to file the transmission application for a four-year test period (2019-2022) in order to align the applications and the test periods for future combined applications. Changes to Hydro One's organization in July and August 2018, combined with the OEB's request, resulted in Hydro One re-evaluating its Transmission Business Plan. To allow sufficient time for this review to occur, Hydro One filed a one-year application to adjust the 2019 transmission revenue requirement for inflation after adjusting for Bill 2 requirements. As a result, the rate estimates noted below span an anticipated three separate rate filings for the periods of 2019, 2020-2022, and 2023-2027, although the length of the latter period may be subject to future OEB direction.

| Transmission Revenue Requirement | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Rates Revenue Requirement** | **$ 1,511** | **$ 1,550** | **$ 1,620** | **$ 1,703** | **$ 1,791** |
| **Rate Increase Required, excl Load** | | **2.6%** | **4.5%** | **5.2%** | **5.1%** |
| Estimated Load Impact | | 0.0% | 3.8% | 0.6% | 0.7% |
| **Rate Increase Required** | | **2.6%** | **8.3%** | **5.8%** | **5.8%** |
| **Est Total Bill Impact (R1 customer - 8%)** | | **0.2%** | **0.7%** | **0.5%** | **0.5%** |

The total bill impact for Hydro One medium density residential (R1) customers consuming 750 kWh monthly is determined based on the forecasted increase in the customer's Retail Transmission Service Rates.

# Revenue Requirement

| Transmission Revenue Requirement | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| OM&A | 394 | 398 | 359 | 365 | 370 |
| Depreciation | 469 | 474 | 488 | 519 | 545 |
| Return on Debt | 302 | 306 | 329 | 348 | 371 |
| Return on Equity | 401 | 406 | 446 | 473 | 503 |
| Income Tax | 57 | 58 | 53 | 56 | 57 |
| Revenue Requirement | $ 1,624 | $ 1,642 | $ 1,675 | $ 1,761 | $ 1,846 |
| Deferral and Variance Accounts | (58) | (38) | 2 | - | - |
| Other revenue impacts | (55) | (55) | (57) | (57) | (56) |
| **Rates Revenue Requirement** | **$ 1,511** | **$ 1,550** | **$ 1,620** | **$ 1,703** | **$ 1,791** |
| **Rate Increase Required, excl Load** | | **2.6%** | **4.5%** | **5.2%** | **5.1%** |
| Estimated Load Impact | | 0.0% | 3.8% | 0.6% | 0.7% |
| **Rate Increase Required** | | **2.6%** | **8.3%** | **5.8%** | **5.8%** |
| **Est Total Bill Impact (R1 customer - 8%)** | | **0.2%** | **0.7%** | **0.5%** | **0.5%** |

Hydro One has taken steps to mitigate the impact of rate increases to customers. The increase in transmission rates in 2019 is largely attributable to the inflationary increase applied for in the 2019 transmission revenue requirement application, as well as changes in the disposition of deferral and variance account balances. Increases in rates during 2020-2022 are largely attributable to the declining load forecast, as described in the following section, as well as increases in depreciation and return on capital reflective of increasing rate base. These increases have been partially offset by decreased OM&A expenses. The rate increases indicated above are relative to the OEB approved revenue requirement for 2018, including the partial sharing of the deferred tax asset (DTA) with customers. As a result of Hydro One's motion to review and vary the decision, the treatment of the DTA is currently under review by the OEB. In the event the OEB alters its decision, the rate impacts noted above will change to reflect the new decision.

### Table 2: Average Bill Impacts on Transmission and Distribution-connected Customers

| | 2019* | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| Rates Revenue Requirement ($ millions) | **$1,552.3** | **$1,628.0** | **$1,719.4** | **$1,808.4** |
| % Increase in Rates Revenue Requirement over prior year | | 4.9% | 5.6% | 5.2% |
| % Impact of load forecast change | | 3.8% | 0.6% | 0.7% |
| **Net Impact on Average Transmission Rates** | | **8.7%** | **6.2%** | **5.9%** |
| *Transmission as a % of Tx - connected customer's Total Bill* | | *7.4%* | *7.4%* | *7.4%* |
| **Estimated Average Bill Impact** | | **0.6%** | **0.5%** | **0.4%** |
| *Transmission as a % of Dx - connected customer's Total Bill* | | *6.2%* | *6.2%* | *6.2%* |
| **Estimated Average Bill Impact** | | **0.5%** | **0.4%** | **0.4%** |

** 2019 rates revenue requirement as per Table 2 in the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on April 25, 2019.*

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 400 kWh, 750 kWh and 1,800 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 3.

### Table 3: Typical Medium Density (R1) Residential Customer Bill Impacts

| | Typical R1 Residential Customer | | |
|---|---|---|---|
| | **400 kWh** | **750 kWh** | **1,800 kWh** |
| Total Bill as of May 1, 2018[1] | $83.40 | $121.75 | $236.81 |
| RTSR included in 2017 R1 Customer's Bill *(based on 2016 UTR)* | $4.78 | $8.96 | $21.50 |
| Estimated 2019 Monthly RTSR[2] | $5.10 | $9.56 | $22.95 |
| **2019 increase in Monthly Bill** | **$0.13** | **$0.24** | **$0.58** |
| *2019 increase as a % of total bill* | *0.2%* | *0.2%* | *0.2%* |
| Estimated 2020 Monthly RTSR[3] | $5.52 | $10.35 | $24.83 |
| **2020 increase in Monthly Bill** | **$0.42** | **$0.79** | **$1.89** |
| *2020 increase as a % of total bill* | *0.5%* | *0.6%* | *0.8%* |
| Estimated 2021 Monthly RTSR[3] | $5.84 | $10.96 | $26.29 |
| **2021 increase in Monthly Bill** | **$0.32** | **$0.61** | **$1.46** |
| *2021 increase as a % of total bill* | *0.4%* | *0.5%* | *0.6%* |

Witness: Clement Li

OM&A allocations are subsequently defined strategically based on customer, operational, public policy and financial outcomes and funding level necessary to meet its objectives.

The basis for this upfront allocation is the expenditure level included in the prior year's plan, adjusted for efficiency gains and new strategic directions as presented in Figure 5 below. The overall investment envelope and year-over-year pacing of investments is also informed by the feedback received through the customer engagement process.

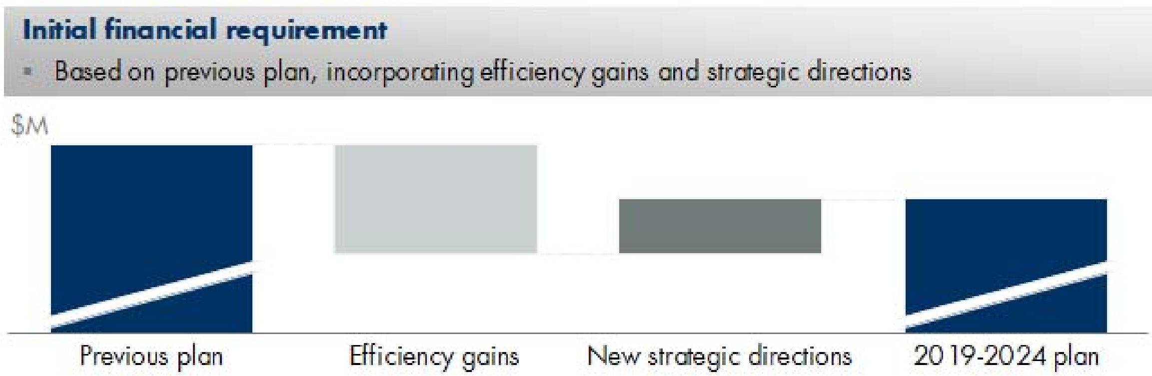



**Figure 5 - Upfront Allocation Setting Framework**

As noted in TSP Section 1.3, through the customer engagement survey, respondents were provided with descriptions of four illustrative investment scenarios (Scenarios A, B, C, D), and provided a line of data points that started at zero and extended beyond the four of the illustrative investment scenarios. Customers were asked to select any point along that continuum that reflected what they believed to be the best and most appropriate balance between rate impacts and outcomes. Scenario C, which maintains the level of investment proposed in the previous application, improves long-term reliability performance and offers level future rate increases, was strongly favored over the other three scenarios. Customer preference for long-term reliability performance with level future rate increases is reflected in the initial funding envelope, which was subsequently divided into smaller, more discrete allocations.

Witness: Bruno Jesus

and prioritized based on the level of risk mitigated and the cost and value delivered toward achieving business objectives.

The overall Investment Planning process is set out below in Figure 1**.**

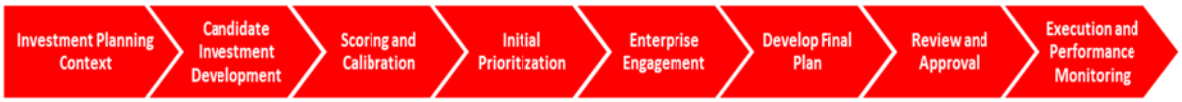



**Figure 1 – Improved Eight-Step Investment Planning Process**

Key improvements to Hydro One's investment planning process include the use of:

- Revised risk assessment framework to provide consistent risk assessment of safety, reliability and environmental risks;
- Clear definitions of risk impacts to enable consistent assessments across investments and calibration sessions to calibrate and align risk assessment practices; and
- Challenge sessions to engage stakeholders across the organization to review the investments and discuss potential trade-offs.

Hydro One management at all levels, including the Executive Leadership Team ("ELT"), are involved in the investment planning process to develop an investment plan that achieves the overall corporate strategy, efficiently mitigates risks, and delivers value to customers.

The Investment Planning process generates an annual budget for Operations, Maintenance and Administration ("OM&A") and capital work programs, and a six-year planning forecast that allows Hydro One to meet the OEB's filing requirements. The 2020-2024 Investment Plan presented in this TSP is a product of the improved investment planning process.

# SEC INTERROGATORY #7

**Reference:**

EB-2016-0160, J8.1, Attachment 1-2

**Interrogatory:**

Please provide a detailed chronology of material events in Hydro One's transmission planning process for the capital plan included in this application similar as to provide in Undertaking J8.1 in EB-2016-0160.

**Response:**

The timeline below includes material events in Hydro One Transmission's Investment and Business Planning processes.

| Date | Activity Category | Activity |
|---|---|---|
| Feb 9/10, 2017 | Customer Engagement | Customer engagement with 88 First Nations communities |
| Spring 2017 | Customer Engagement | Customer engagement content developed |
| May 3, 2017 | Customer Engagement | Final customer engagement survey submitted |
| May 11 – June 15, 2017 | Customer Engagement | Customer engagement field survey |
| May 13, 2017 | Customer Engagement | Customer engagement with 29 Metis Councils |
| May 31, 2017 | Customer Engagement | Interim customer engagement report |
| June 9, 2017 | Customer Engagement | Customer engagement survey concluded |
| July 2, 2017 | Customer Engagement | Final customer engagement report |
| Summer 2017 | Investment Planning | Initial enhancements made to investment planning process |
| December 8, 2017 | Strategic Decision | Hydro One Board approved 2018-23 Business Plan |
| February 12, 2018 | Strategic Decision | Discussion with Hydro One Board on filing of a 5-year Tx application for the 2019-23 period in late April 2018 |
| February 21, 2018 | Customer Engagement | Customer engagement with 88 First Nations communities |
| December 2017 – May 2018 | Benchmarking | Special studies and benchmarking results:<br>- Asset hazard curves / degradation rates<br>- Asset replacement practices / expected service life<br>- Investment planning process<br>- Asset analytics and reliability risk modeling |

Witness: Bruno Jesus, Joel Jodoin

| | | |
|---|---|---|
| February 2018 | Strategic Decision | 2018 Corporate Priorities announced |
| March 16, 2018 | Strategic Decision | OEB letter regarding expectation to file a joint Tx/Dx application for 2023-27 period, requiring a change to planned regulatory filing |
| Spring 2018 | Investment Planning | Enhancements to investment planning process, incorporating findings from investment planning process review |
| April 2018 | Investment Planning | Investment Planning Context Setting phase initiated |
| May-June 2018 | Investment Planning | Planners input candidate investments into AIP tool |
| June 28, 2018 | Business Planning/ Investment Planning | Executive Leadership Team review of initial envelopes |
| Late June | Investment Planning | Management review of individual candidate investment proposals |
| Early July 2018 | Investment Planning | Investment Calibration |
| August 14, 2018 | Strategic Decision | New Board of Directors announced |
| August – September 2018 | Investment Planning | Prioritization and risk optimization of candidate investments and challenge trade-off sessions |
| October 1, 2018 | Transmission Application | Discussion with new Hydro One Board on filing 1-year inflationary increase for 2019 rates followed by a 3-year Custom Incentive Rate application. |
| October 2018 | Investment Planning | Operational stakeholder (“enterprise”) engagement on preliminary list of prioritized investments. |
| Late October – early November | Business Planning/ Investment Planning | Final review of investment plan |
| October 26, 2018 | Transmission Application | Hydro One files rate application for 2019 revenue requirement (EB-2018-0130) |
| September-November 2018 | Business Planning | 2019-24 Business Plan developed, using the Investment Plan, overhead information, and productivity targets, to finalize plan figures (revenue requirement). |
| November 30, 2018 | Business Planning | Executive Leadership Team approval of 2019-24 business plan |
| December 14, 2018 | Business Planning | Hydro One Board of Directors approval of 2019-24 business plan |
| March 21, 2019 | Transmission Application | Hydro One files rate the Application |

# SEC INTERROGATORY #27

**Reference:**
TSP-02-01

**Interrogatory:**
Please provide a table that shows both the total, and for each category of capital expenditures (i.e. system renewal, system service etc), the number of candidate investments considered/included in each stage of the investment planning process.

**Response:**
The total number of candidate investments considered at each stage of the investment planning process for the current application is outlined in Table 1 below.

**Table 1: Number of Candidate Investments**

| Category | Investment Planning Process Stage | | | |
|---|---|---|---|---|
| | Candidate Investment Development | Prioritization and Optimization | Enterprise Engagement | Develop Final Plan/Review and Approval |
| **System Renewal** | 80 | 84 | 85 | 84 |
| **System Access** | 348 | 313 | 319 | 340 |
| **System Service** | 41 | 44 | 44 | 44 |
| **General Plant** | 108 | 91 | 93 | 95 |
| **Total** | **577** | **532** | **541** | **563** |

Witness: Bruno Jesus

# SEC INTERROGATORY #28

**Reference:**
TSP-02-01

**Interrogatory:**
Please provide a table that shows both the total, and for each category of capital expenditures (i.e. system renewal, system service etc), the capital expenditure budget at each stage of the investment planning process. (Note: For reference to a similar chart from the previous proceeding, see Undertaking J8.1, Attachment)

**Response:**
The capital expenditures at each stage of the investment planning process are outlined in Table 1 below.

**Table 1: Capital Spending Forecast (Millions)**

| Category | Investment Planning Process Stage | | | |
|---|---|---|---|---|
| | Candidate Investment Development | Prioritization and Optimization | Enterprise Engagement | Develop Final Plan/Review and Approval |
| **System Access** | 87 | 85 | 63 | 65 |
| **System Renewal** | 6,326 | 4,989 | 4,992 | 5,512 |
| **System Service** | 727 | 1,027 | 1,018 | 883 |
| **General Plant** | 476 | 439 | 439 | 447 |
| **Progressive Productivity Placeholder** | N/A | N/A | N/A | (286) |
| **Directive Adjustment**[1] | N/A | N/A | N/A | (2) |
| **Total** | **7,616** | **6,540** | **6,511** | **6,619** |

[1] The Directive Adjustment reflects the impact of the directive issued by Ontario's Management Board of Cabinet on February 21, 2019 and the associated compensation framework they approved on March 7, 2019. Refer to Exhibit F, Tab 4, Schedule 1 for further details.

Witness: Bruno Jesus

# SEC INTERROGATORY #29

**Issue from Draft List:**
[Issue Group]

**Reference:**
TSP-02-01

**Interrogatory:**
Please explain what overall budget constraints were included in the investment planning process.

**Response:**
As described in Exhibit B, Tab 1, Schedule 1, Section 2.1, page 8, the basis for the upfront allocation was based on the expenditure level included in the prior year's plan, adjusted for efficiency gains and new strategic directions as presented in Figure 5, which was informed by feedback received through the customer engagement process.

The budget constraints reflect an appropriate balance between rate impacts and outcomes, consistent with customer preference for Scenario C, which reflects long-term reliability performance improvement with level rate increases in the future (as opposed to higher future rate increases for example). The total 5 year capital investment plan associated with Scenario C was $6.6B from 2019-2023, or $1.3B per year on average.

Witness: Bruno Jesus, Joel Jodoin

# SEC INTERROGATORY #30

**Reference:**
TSP-02-01

**Interrogatory:**
Please explain where rate impact is considered within the investment planning process.

**Response:**
Rate impacts are directly considered during the following investment planning process phases:

- Investment planning context: rate impacts are considered as part of the overall envelope setting process, informed by customer engagement feedback, risk, and consideration of asset and system needs.
- Prioritization and optimization: rate impacts are considered as part of portfolio review and trade-off discussions of investments
- Review and approval: rate impacts are considered as part of the approval of the business plan.

Witness: Bruno Jesus, Joel Jodoin

# UNDERTAKING - JT 1.12

**Reference:**

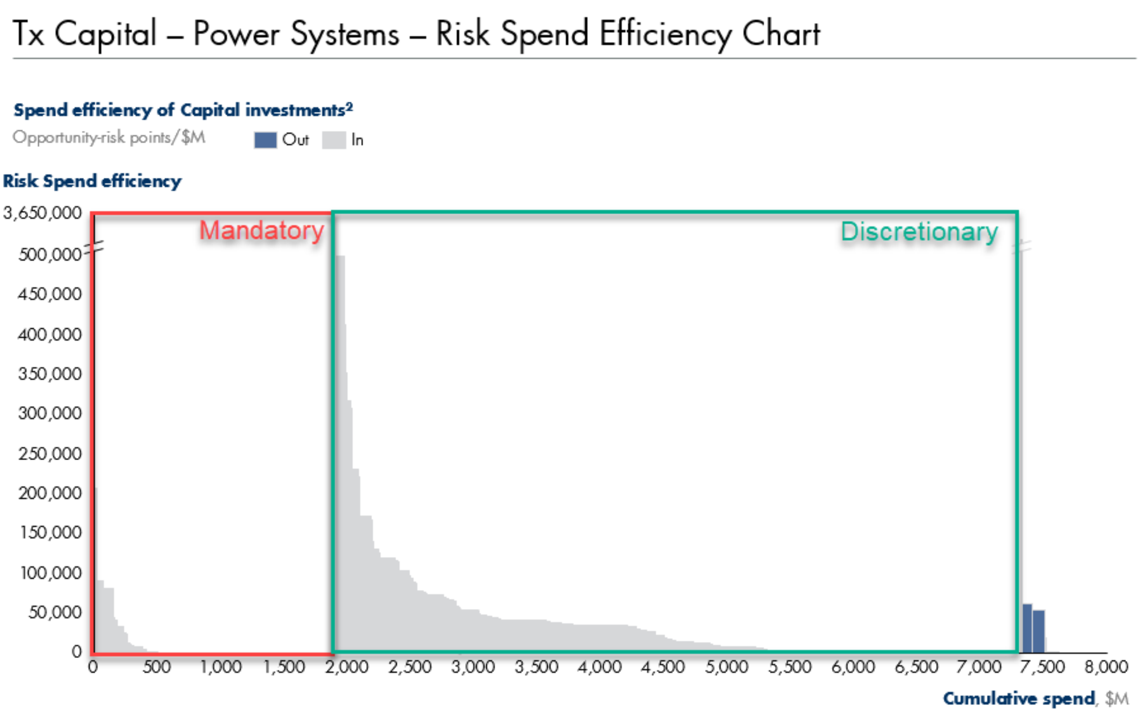
I-07-SEC-032, part a)

**Undertaking:**

To provide data clarifying costs and risk score (reference SEC IR 32).

**Response:**

The table below has been structured in a manner consistent with the pre-filed evidence to allow for a meaningful comparison. Investments have been categorized as either mandatory or discretionary, consistent with the criteria described in Exhibit B, Tab 1, Schedule 1, Section 2.1. The graph included in SEC-32, includes mandatory investments, and subsequently discretionary investments, with expenditures planned over the 2019-24 period, as shown below:




1. Includes Power System investments only. Value for other allocations are primarily evaluated on productivity or flagging basis
2. Ranking based on investments flagged as Mandatory followed by Risk Spend Efficiency. For presentation purposes, investments with an efficiency rating greater than 500k points have been set at 500k; those with an efficiency raring of 0 have been set at 10

Mandatory investments meet one of the four mandatory flag criteria outlined in TSP 2.1, page 37 and reproduced below:

Witness: Bruno Jesus

- **Immediate / Short-term Compliance –** Explicit obligation to a regulatory agency (e.g. OEB requires work to be done *within a year* with *immediate risk* of legal breach, or there is a *two to five-year risk* of regulatory or legal breach);
- **Third party requests –** Explicit connection request by a city, county, agency, or customer, with a *one to five-year risk* of breaking the utility obligation to serve;
- **Contractual –** Signed, fixed-sum contracts with third parties for services such as IT support, facility support, etc.; and
- **In-Flight –** Project already under construction.

In some cases, mandatory investments were not re-scored because they were in-flight, or were scored low based on a compliance obligation.

| | ISD | ISD Name | 2019-2024 Spend ($ M) | Total Risk Mitigation | Risk Spend Efficiency[1] |
|---|---|---|---|---|---|
| Mandatory[2] | SA-01 | Connect New IAMGOLD Mine | 10 | - | - |
| | SA-02 | Horner TS: Build a Second 230/27.6kV Station | 6 | - | - |
| | SA-03 | Halton TS: Build a Second 230/27.6kV Station | 6 | - | - |
| | SA-04 | Connect Metrolinx Traction Substations | 11 | - | - |
| | SA-05 | Future Transmission Load Connection Plans | 19 | - | - |
| | SA-06 | Protection and Control Modifications for Distributed Generation | - | 879,930 | 500,000 |
| | SA-07 | Secondary Land Use Projects | - | - | - |
| | SR-01 | Air Blast Circuit Breaker Replacement Projects | 219 | 10,897,936 | 49,845 |
| | SR-02 | Station Reinvestment Projects | 142 | 115,142 | 813 |
| | SR-03 | Bulk Station Transformer Replacement Projects | 20 | 251,406 | 12,274 |
| | SR-05 | Load Station Transformer Replacement Projects | 51 | 65,233 | 1,272 |
| | SR-06 | Load Station Switchgear and Ancillary Equipment Replacement Projects | 20 | 21,795 | 1,088 |
| | SR-10 | Transformer Protection Replacement | 7 | - | - |
| | SR-15 | Telecom Fibre IRU Agreement Renewals | 15 | 3,190,264 | 206,982 |
| | SR-19 | Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures | 49 | 585,075 | 11,967 |
| | SR-24 | Transmission Line Shieldwire Replacement | 74 | 665,383 | 8,982 |
| | SR-26 | Transmission Line Emergency Restoration | 59 | 1,992,879 | 33,552 |

[1] Investments with an efficiency rating of 0 are either in-flight or driven by regulatory compliance, contractual commitments, customer requests or economical efficiencies.
[2] Certain System Renewal investment are included in both the Mandatory and Discretionary categories based on the taxonomies as certain sites are currently in-flight. Refer to TSP 2.1 pages 37-38 for mandatory/discretionary categorization.

| | ISD | ISD Name | 2019-2024 Spend ($ M) | Total Risk Mitigation | Risk Spend Efficiency[1] |
|---|---|---|---|---|---|
| | SS-01 | Lennox TS: Install 500kV Shunt Reactors | 46 | - | - |
| | SS-02 | Wataynikaneyap Power Line to Pickle Lake Connection | 30 | - | - |
| | SS-03 | Nanticoke TS: Connect HVDC Lake Erie Circuits | - | - | - |
| | SS-04 | East-West Tie Connection | 127 | - | - |
| | SS-05 | St. Lawrence TS: Phase Shifter Upgrade | 18 | - | - |
| | SS-06 | Merivale TS to Hawthorne TS: 230kV Conductor Upgrade | 24 | - | - |
| | SS-07 | Milton SS: Station Expansion and Connect 230kV Circuits | 194 | - | - |
| | SS-08 | Northwest Bulk Transmission Line | 35 | - | - |
| | SS-09 | Barrie Area Transmission Upgrade | 75 | - | - |
| | SS-10 | Kapuskasing Area Transmission Reinforcement | 28 | - | - |
| | SS-11 | South Nepean Transmission Reinforcement | 1 | - | - |
| | SS-12 | Alymer-Tillsonburg Area Transmission Reinforcement | 30 | - | - |
| | SS-13 | Leamington Area Transmission Reinforcement | 206 | - | - |
| | SS-14 | Southwest GTA Transmission Reinforcement | 33 | - | - |
| | SS-15 | Future Transmission Regional Plans | 44 | - | - |
| | SS-16 | Customer Power Quality Program | 20 | - | - |
| | | Less than $3M | 296 | 5,272,230 | 17,814 |
| Discretionary | GP-02 | Grid Control Network Sustainment | 41 | 772,412 | 18,926 |
| | GP-05 | Transmission Non-Operational Data Management System | 23 | 25,420 | 1,125 |
| | SA-07 | Secondary Land Use Projects | 7 | - | - |
| | SR-01 | Air Blast Circuit Breaker Replacement Projects | 464 | 60,937,116 | 131,344 |
| | SR-02 | Station Reinvestment Projects | 458 | 22,478,975 | 49,088 |
| | SR-03 | Bulk Station Transformer Replacement Projects | 392 | 22,150,917 | 56,472 |
| | SR-04 | Bulk Station Switchgear and Ancillary Equipment Replacement Projects | 176 | 65,981,862 | 374,265 |
| | SR-05 | Load Station Transformer Replacement Projects | 719 | 10,637,910 | 14,799 |
| | SR-06 | Load Station Switchgear and Ancillary Equipment Replacement Projects | 225 | 10,137,180 | 45,150 |
| | SR-07 | Protection and Automation Replacement Projects | 64 | 10,084,973 | 158,113 |
| | SR-08 | John Transformer Station Reinvestment Project | 86 | 1,465,442 | 17,038 |
| | SR-09 | Transmission Station Demand and Spares and Targeted Assets | 243 | 7,269,990 | 29,886 |
| | SR-11 | Legacy SONET System Replacement | 115 | 1,008,208 | 8,731 |
| | SR-13 | ADSS Fibre Optic Cable Replacements | 4 | 484,854 | 114,499 |

Witness: Bruno Jesus

| | ISD | ISD Name | 2019-2024 Spend ($ M) | Total Risk Mitigation | Risk Spend Efficiency[1] |
|---|---|---|---|---|---|
| | SR-14 | Mobile Radio System Replacement | 20 | 201,590 | 10,170 |
| | SR-19 | Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures | 481 | 996,525 | 2,072 |
| | SR-20 | Transmission Line Refurbishment - Near End of Life ACSR Conductor | 506 | 355,060 | 702 |
| | SR-21 | Wood Pole Structure Replacements | 300 | 12,487,336 | 41,607 |
| | SR-22 | Steel Structure Coating Program | 111 | - | - |
| | SR-25 | Transmission Line Insulator Replacement | 407 | 14,289,148 | 35,117 |
| | SR-27 | C5E/C7E Underground Cable Replacement | 127 | 176,963 | 1,390 |
| | SR-28 | OPGW Infrastructure Projects | 32 | 321,485 | 10,041 |
| | | Less than $3M | 402 | 20,108,484 | 50,065 |
| Excluded | | Less than $3M | 360 | 32,790,878 | 91,171 |

As part of Enterprise Engagement and Challenge Sessions, trade-off decisions assess which investments should be promoted or demoted based on the following levers:

- **Risk:** Is Hydro One comfortable with the remaining risk? Are there unfunded investments which mitigate large risks?
- **Flags (non-risk parameters):** Which investments need to be funded for non-risk merits?

The consideration of risk efficiency and risk mitigated per dollar and other considerations supports the making of prudent and data-driven trade-off decisions. Investments that were prioritized out of the plan ("Excluded") have not been included in this application; examples of these candidate investments included power system telecom investments, station reinvestment and component replacements, replacement of wood pole structures in non-publicly accessible locations, and future line refurbishments which are expected to be assessed to be end-of-life at a later date.

# Making Choices: Illustrative Scenarios

Now we would like to take one last look at the core trade-offs Hydro One must make as it begins its business planning for 2019 to 2023:

- the balance between the level of investment and system reliability, and
- the timing of those investments.

**To help understand your priorities, Hydro One has developed four illustrative scenarios**. The specific priority of investment items in these scenarios is based on the priorities used in Hydro One's proposal currently before the Ontario Energy Board. While those priorities may change based on your earlier feedback, these scenarios are illustrative of the impacts of various spending levels.

In considering these scenarios, please be advised that all figures are intended as approximate, and are not intended to be relied upon as exact.

These scenarios focus on the trade-offs between the pace of investment, reliability, and future rate increases. The higher the level of investment, the lower the reliability risk 🕮, and vice-versa. As you consider these illustrative scenarios, please bear in mind that your rates can also be impacted by changes in load forecast and electricity prices. All scenarios assume an Operations, Maintenance, and Administration (OM&A) expense percentage increase that is held to less than inflation.

*By preparing and providing these illustrations, Hydro One makes no representation that it will select one as its plan before the Ontario Energy Board.*

Please read each scenario to understand how different investment levels impact key outcomes. You can choose one of these scenarios, a point between these scenarios or a point above or below these scenarios. There is a follow-up question that allows you to discuss the factors that you considered in making your choice. Your comments will help us better understand the outcomes you value.

These descriptions refer to "key assets" which are conductors, circuit breakers and transformers, as their failure is most likely to impact system reliability.

## Scenario A: Limited investment

- Capital investment focused on regulatory requirements and customer demand projects, such as new connections
- Sustainment capital limited to replacing assets subject to imminent failure; no proactive sustainment investment
- The percentage of key assets beyond Expected Service Life will increase from 21% in 2019 to 29% in 2023, increasing expected future investment requirements
- Total 5 year Capital Investment Plan: $1.8 B
- Average Annual Transmission Rate Increase: 1.3%

## Scenario B: Decrease in current level of investment

- Capital investment reduced compared to plan filed with the Ontario Energy Board in May 2016
- Spending on sustainment of key assets deferred to future years
- Contains lower levels of investment in productivity and fewer strategic investments designed to mitigate future rate impacts (e.g., tower coating)
- The percentage of key assets beyond Expected Service Life increases from 21% in 2019 to 26% in 2023, increasing expected future investment requirements and expenses
- Additional capital in Scenario B as compared to Scenario A focuses on replacing assets in poorest condition, resulting in a significant reduction in reliability risk
- Total 5 year Capital Investment Plan: $4.3 B
- Average Annual Transmission Rate Increase: 3.3%

## Scenario C: Maintain current level of investment

- Extends investment plan in rate application currently before the Ontario Energy Board to 2023
- Maintains current level of sustainment capital 🕮 investments affecting key assets
- Percentage of key assets beyond Expected Service Life 🕮 decreases from 21% in 2019 to 19% in 2023, decreasing expected future investment requirements
- Incorporates strategic investments that mitigate future rate impacts, such as tower coating
- Total 5 year Capital Investment 🕮 Plan: $6.6 B
- Average Annual Transmission Rate Increase: 5.1%

## Scenario D: Increase beyond the current level of investment

This plan contains all investments in Scenario C, with addition of:

- Additional sustainment capital 🕮 focused on key assets
- As a result, the percentage of key assets beyond Expected Service Life 🕮 decreases from 21% in 2019 to 17% in 2023, decreasing expected future investment requirements
- While the above investments benefit all customers to some degree, this scenario also increases capital to add redundancy 🕮 to worst performing single circuits 🕮 in system, benefiting a very small portion of customers in a significant way
- Total 5 year Capital Investment 🕮 Plan: $7.4 B
- Average Annual Transmission Rate Increase: 5.6%

# Exploring Trade-offs Using Illustrative Scenarios

Below is a chart summarizing all the scenarios from the previous page and their implications. As we mentioned these examples are meant to illustrate the impacts of different levels of investment on current and future rate increases and system reliability.

You will note that the two middle scenarios, B and C, offer a relatively small change in reliability risk, but moving from B to C offers significant improvements in long-term reliability. The key difference between B and C is that B has larger future increases, while C has level future rate increases. The big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers.

As noted earlier, by offering these illustrative scenarios, Hydro One is not committing to any of them; their purpose is to help Hydro One understand what you as a customer value. When Hydro One makes its Ontario Energy Board filing, Hydro One will incorporate feedback received through this process, but does not commit to pursuing any one of these illustrative scenarios.

Below the chart is a slider which represents the range of potential approaches Hydro One can take. On the far left is lower investment, lower short-term rates, lower reliability, and higher anticipated future increases. On the far right is higher investment, higher short-term rates, higher reliability, and lower anticipated future increases. Please use the slider to indicate what approach you think Hydro One should take. Hydro One will use the results of this exercise as a directional indicator of the route customers want to go.

*NB: The location on the slider does not correlate directly with potential rate increases. (For example, while the physical distance between scenarios B and C is the same as between C and D, the impact on reliability, rates and other outcomes is very different).*

*See the "Additional Information" document to view a larger and more detailed version of this table.*

| | Illustrative Scenarios | | | |
|---|---|---|---|---|
| | **A: Limited investment** | **B: Decrease in current level of investment** | **C: Maintain current level of investment** | **D: Increase beyond the current level of investment** |
| **5 Year Capital Investment** | $1.8 B | $4.3 B | $6.6 B | $7.4 B |
| **Reliability Risk** | Increase in risk ~30% | Increase in risk ~10% | Decrease in risk ~10% | Decrease in risk ~15% |
| **Long-term Reliability Impact** | ↓ | ↓ | ↑ | ↑* |
| **Average Percentage of Key Assets Beyond Expected Service Life by end of 2023 (21% in 2019)** | 29% | 26% | 19% | 17% |
| **Impact on Future rates** | Significantly higher future rate increases | Higher future rate increases | Level future rate increases. | Slightly lower future rate increases. |
| **Average Annual Total Bill Impact – Transmission Connected Customer** | 0.11% | 0.27% | 0.42% | 0.46% |
| **Average Annual Transmission Rate Increase** | 1.30% | 3.30% | 5.10% | 5.60% |

* Improvement in overall long term reliability and significant performance improvement for small number of customers connected to the worst performing circuits.

Thinking of all the considerations outlined, please choose a point along the line below that you believe strikes the right balance between rates and outcomes. (Remember you can choose a point located between scenarios or directly aligned with them).

**Scenario A** | **Scenario B** | **Scenario C** | **Scenario D**

Lower increases now
Higher future increases
Lower reliability

Higher increases now
Lower future increases
Higher reliability

❍ Not sure / Don't know

**Comments:** Please use this space to tell us why you placed the slider where you did.

# OEB INTERROGATORY #83

**Reference:**
TSP-01-04-15 p. 5 TSP-03-03 p. 4

**Interrogatory:**
At the second reference above, Hydro One stated the following:

System Renewal investments will increase 5.5% over the course of this TSP, with investment in both stations and line refurbishment seeing a 5.7%, and 5.5% increase over the plan, respectively. The objective over the planning period is to return to top quartile reliability performance and this level of spending is designed to accomplish this objective.

a) How were the reliability performance targets shown in Figure 2 selected?

b) How was the top quartile performance target determined? Is this an internal Hydro One target or was this target set by others?

c) If the target is set by others, were they aware at the time that such a large capital spending increase would be necessary to meet the performance target?

d) What is the basis for confidence that the proposed spending is necessary to deliver the target performance levels? In other words, how was the performance outcome calculated based upon the proposed spending levels?

e) Given that cost concerns are the biggest issue for most ratepayers, how did Hydro One determine that a top quartile performance target is appropriate for such a large system covering such a range of load densities, geographies and climatic regions?

**Response:**
a) The objective is to return to top quartile reliability, which includes managing the condition of the assets to continue to reliably perform their functionality. In Figure 2, the values are estimated end-of-plan outcomes. These outcomes were based on the initial allocation work done early in the planning process.

Witness: Bruno Jesus

b) The top quartile target is a strategic business objective to achieve top tier reliability performance and validated consistent with the customer engagement process. This is an internal Hydro One target based on Hydro One's interpretation of customers expressed preference for reliable service. The customer engagement survey feedback was clear that reliability performance is a priority outcome.

c) Please refer to b) above.

d) The performance outcome was calculated based upon the last 10 years of performance data and a high level target to achieve 2% improvement per year. The performance outcome is expected to be met through the integration of key reliability initiatives, referenced in OEB-018, part c.)

e) Cost was not the biggest issue raised through the customer engagement process; please refer to Exhibit B, Tab 1, Schedule 1, Section 1.3 for a listing of customers' top priorities. Refer to b, above.

Witness: Bruno Jesus

# UNDERTAKING - JT 1.15

**Reference:**
TSP 1.3, Attachment 1

**Undertaking:**
To provide data similar to what was provided in EB-2016-0160, IR Staff 15, page 6, figure 1, breaking down risk reliability for each of four scenarios and how they were derived.

**Response:**
The reliability risk model is a simplified method to communicate risk to customers and stakeholders, and is not used to identify specific asset needs or justify investments. The reliability risk model was one of several measures used in the 2017 Customer Engagement Survey to communicate the outcomes associated with various investment scenarios. The reliability risk scenario data presented as part of the Customer Engagement, reflects the relative change in forecast reliability risk from January 1, 2019 to December 31, 2023. The scenarios are illustrative only and do not reflect the specifics of the plan later developed based on the directional feedback received from customers.

As described in Exhibit B-1-1, Section1.4, Attachment 13, the reliability risk model uses hazard curves that describe the asset survival risk by asset type. Hydro One’s hazard curves are based on a report prepared by Foster Associates, which is based on an analysis of Hydro One's historical data. Subsequently, the demographic profile of the asset is multiplied by the age-specific hazard rate to obtain a risk profile for the assets as a function of their age used to compute the fleet risk. The overall probability is the sum of this profile.

For the purpose of the Customer Engagement, five reference points were calculated, including four illustrative scenarios:

- Current State (projected as of January 1, 2019)
- Scenario A (projected as of December 31, 2023)
- Scenario B (projected as of December 31, 2023)
- Scenario C (projected as of December 31, 2023)
- Scenario D (projected as of December 31, 2023)

The forecast state of these asset fleets is subsequently multiplied by the historical contribution of each of the asset classes to the equipment reliability outages (duration) over the 2011-15 period. As a result of the increased number of scenarios, the derivation of the reliability risk figures presented during the Customer Engagement process have been included below in a slightly different format:

**Table 1: Historical Interruption Duration**

| | **% of Interruption Duration (2011-15)** |
|---|---|
| **Lines** | 69% |
| **Transformers** | 6% |
| **Breakers** | 9% |
| **Other** | 16% |

**Table 2: Supporting Data – Fleet Risk**

| | **Supporting Data – Fleet Risk** | | | | |
|---|---|---|---|---|---|
| | **Jan 1, 2019** | **Scenario A** | **Scenario B** | **Scenario C** | **Scenario D** |
| **Lines** | 1.11% | 1.42% | 1.22% | 0.96% | 0.92% |
| **Transformers** | 2.66% | 3.86% | 3.19% | 2.77% | 2.77% |
| **Breakers** | 1.62% | 1.92% | 1.68% | 1.32% | 1.32% |

**Table 3: Calculation of Asset Reliability Risk**

| | **Calculation – Asset Reliability Risk [ Fleet Risk x % of Interruption Duration]** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Jan 1, 2019** | | **Scenario A** | | **Scenario B** | | **Scenario C** | | **Scenario D** | |
| Lines | 1.11% x 69% = | 0.77% | 1.42% x 69% = | 0.98% | 1.22% x 069% = | 0.84% | 0.96% x 69% = | 0.66% | 0.92% x 69% = | 0.63% |
| Transformers | 2.66% x 6% = | 0.16% | 3.86% x 6% = | 0.23% | 3.19% x 6% = | 0.19% | 2.77% x 6% = | 0.17% | 2.77% x 6% = | 0.16% |
| Breakers | 1.62% x 9% = | 0.15% | 1.92% x 9% = | 0.17% | 1.62% x 9% = | 0.15% | 1.32% x 9% = | 0.12% | 1.32% x 9% = | 0.11% |
| **Total** | 0.77% + 0.16% + 0.15% = | **1.07%** | 0.98% + 0.23% + 0.17% = | **1.39%** | 0.84% + 0.19% + 0.15% = | **1.19%** | 0.66% + 0.17% + 0.12% = | **0.95%** | 0.63% + 0.16% + 0.11% = | **0.91%** |

**Table 4: Change in Asset Reliability Risk**

| | **Calculation – Change in Asset Reliability Risk** | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Scenario A** | | **Scenario B** | | **Scenario C** | | **Scenario D** | |
| Change Relative to Jan 1, 2019 | (1.39 / 1.07) – 1 = | **30%** | (1.19 / 1.07) – 1 = | **11%** | (0.95 / 1.07) – 1 = | **-11%** | (0.91 / 1.07) – 1 = | **-15%** |
| As presented in Customer Engagement | Increase in risk ~30% | | Increase in risk ~10% | | Decrease in risk ~10% | | Decrease in risk ~15% | |

As discussed in Exhibit B, Tab 1, Schedule 3, Attachment 4, the reliability risk model was initially introduced as a simplified method to communicate the value of renewal investments to customers and stakeholders and to provide a directional indicator to assess the effect of an investment portfolio on reliability risk. It is not used to identify specific asset needs or justify investments. Asset needs are anchored by asset condition assessments and investments are justified by asset needs and prioritized in accordance with Hydro One's investment planning approach described in TSP Section 2.1, Investment Planning Process.

The reliability risk scenario data presented as part of the Customer Engagement was solely illustrative and does not reflect the specifics of the plan later developed based on the directional feedback received from customers.

# ***UNDERTAKING – J6.1***

## ***Undertaking***

TO PROVIDE A BREAKDOWN OF AGGREGATE CONTRIBUTION OF LINES

## ***Response***

Reference is made to Table 1 of Exhibit B1, Tab 2, Schedule 4. Listed below are the lines sub-categories and their respective contributions to the lines equipment total of 69% in that Table 1.

| LINES SUB-EQUIPMENT CATEGORIES | Contribution to LINES CATEGORY |
|---|---|
| INSULATOR FAILURE | 26% |
| STEEL CROSS ARM FAILURE | 19% |
| CONDUCTOR FAILURE | 15% |
| WOOD CROSS ARM FAILURE | 13% |
| SKYWIRE FAILURE | 12% |
| WOOD STRUCTURE FAILURE | 7% |
| HARDWARE FAILURE | 3% |
| OTHER | 3% |
| STEEL STRUCTURE FAILURE | 1% |

Witness: Scott McLachlan

The OEB finds that Hydro One should continue to make improvements to its planning process addressing the issues that have been identified in this proceeding as well as those identified in Hydro One's internal audit, and to report on the progress made in this area in its next transmission rate application. Some of the elements that require more focus include a consistent, comprehensive asset condition assessment process which directly links to the TSP and the capital investment plan; an appropriate pacing of capital expenditures that achieves a proper balance of need and rate impact; and Hydro One's ability to execute the proposed capital program in a timely fashion.

The OEB requires Hydro One to complete an independent third-party assessment of its TSP and to file this assessment with its next transmission rate application. This assessment should include Hydro One's asset condition assessment and capital investment planning processes. While this type of assessment is not a standard requirement in similar rate cases, the OEB finds on a case-by-case basis that such an assessment could be beneficial in providing confidence to both the OEB and the applicant going forward. This assessment was suggested by the OEB in Hydro One's last transmission rate application. Hydro One's reason for not doing so, as articulated in the current proceeding, is that it had to forego this assessment in favour of conducting a customer engagement process prior to developing its capital investment plan.[25]

In the OEB's view, this demonstrates inadequate planning on the part of Hydro One given that a third-party review would have best been completed long before the investment plans were finalized and would have given more confidence to Hydro One's customers in the customer engagement process.

## 4.2 CUSTOMER ENGAGEMENT AND RELIABILITY RISK MODEL

Hydro One's evidence on customer engagement was summarized in its Argument-in-Chief[26], where Hydro One maintained that its TSP was consistent with the RRF and 2016 Rate Handbook requirements, and was informed by a customer engagement process appropriately structured to identify customer needs and preferences.

Hydro One indicated that its goal was to engage with customers consistently and proactively to better understand customers and enhance its ability to provide services that meet their needs and improve customers' overall satisfaction with the service they receive.

[25] Exhibit I/Tab1/Schedule 8
[26] Hydro One Argument-in-Chief, p. 23

One critical element of achieving this goal is the development of an investment plan that is outcome-focused and designed to meet customers' needs and preferences.[27]

Hydro One maintained that it has engaged in an intense and focused level of customer engagement in preparing this application,[28] and provided a detailed listing of all the sources it uses to determine customer needs; including routine communications, customer forums, working groups, advisory boards and conferences, and ongoing customer survey research.

For this particular application, Hydro One undertook a further customer engagement initiative, with the purpose of identifying the needs and preferences of customers related to the formulation of a five-year transmission system plan. This initiative was structured to identify customer needs and preferences and allow for the consideration of those customer needs and preferences in preparing the TSP as submitted in this application.

Hydro One engaged Ipsos Reid, a global market research company, to assist in the design, execution, facilitation, and documentation of the customer engagement initiative. Ipsos Reid also undertook analysis of the feedback received during the consultations.

Hydro One indicated that it found the feedback from these sessions to be critical in understanding customer preferences and being better able to identify customer needs. Customers indicated that the consultations were valuable to them in understanding Hydro One's operations and investment process.

Hydro One also indicated that it expects to continue to engage customers in the future, not only to receive input to consider in the development of future investment plans, but also to receive feedback and communicate key information about the system and investments that have or are likely to impact transmission system reliability risk and actual system performance.

In general, based on the customer engagement process, Hydro One submitted that it believes that any deterioration in current service levels is unacceptable to customers and that the maintenance of current reliability levels is a customer priority.

### Timing of the Engagement

[27] Exhibit A/Tab 3/Schedule 1, p. 5
[28] Exhibit B1/Tab 2/Schedule 2

Many intervenors and OEB staff submitted that the customer engagement event took place too close to the filing date of the application to allow any real change to be made if it was warranted by the results of the engagement exercise. Indeed, very little change was made to the TSP as a result of customer engagement.

Some parties also pointed out that poor participation was likely due in part to short timeframe for engagement and questioned whether the results were representative given the poor participation levels.

### Selection of the Participants

The entities invited to participate in Hydro One's focused customer engagement process were directly connected transmission customers and registered intervenors from the last two rate applications. Given the requirements in Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications, staff submitted that this approach was reasonable. However, OEB staff recommended that Hydro One, in its ongoing efforts at customer engagement, remind local distribution company (LDC) participants that they are the source for the transmitter's knowledge of small end-use customers' views and preferences. Hydro One could have asked the LDC participants to specifically present the results of their own customer engagement exercises to inform the transmitter of the concerns of these customers.

In light of the Anwaatin evidence, staff also encouraged Hydro One to obtain information about the needs of these customers through the participation of Hydro One Distribution, Hydro One Remotes, other distributors that serve First Nations, and the Anwaatin First Nations and other First Nations organizations, in Hydro One transmission's ongoing customer engagement exercise.

Both Anwaatin and the Society submitted that Hydro One should more specifically engage First Nations and Métis groups prior to its next application. In addition, a number of parties stated that Hydro One should have engaged more with end-use customers.

## Consideration of Costs

Staff submitted that the main conclusion drawn by Hydro One from the engagement sessions was that reliability was important to customers, and that they were willing to accept increased capital spending to ensure no diminution of reliability. This conclusion supported a slight increase in the proposed capital expenditures, and Hydro One argues that the resulting revenue requirement increases are "consistent with the expressed customer preferences and tolerances regarding reliability risk".[29]

Staff pointed out that it appears that the material presented to customers assumed that customers would tolerate some cost increases above historic levels. The lowest cost scenario presented to customers proposed a spending increase 1.6% higher than historic spending increases, and Hydro One indicated this spending level would result in a 10% increase in "reliability risk". Customers who enquired about a "zero" scenario that presumed a cost increase consistent with historic cost increases were told that “reliability risk” would increase by 20% under such a scenario. A true "zero" scenario which involved no cost increase was not entertained by Hydro One, as the company believed the consequent deterioration of reliability was not acceptable. Staff submitted that the customer engagement exercise emphasised potential threats to reliability at the expense of a discussion probing customers’ views on and tolerance of cost increases.

Many parties criticized the scenarios presented to customers as limited and designed to push customers to Hydro One’s preferred outcome and providing insufficient detail for customers to understand what was being presented. A number of intervenors also submitted that Hydro One had omitted pertinent information such as the fact that the reliability of Hydro One’s transmission system has been improving. They highlighted that Hydro One focused on the dramatic increases in equipment outage hours instead of the dramatic improvement in customer interruption hours between 2011 and 2015.

### Reliability Risk Model

OEB staff's main criticism of Hydro One's customer engagement process is that the choices presented to customers were based on a model for "reliability risk" that was not predictive of real-world reliability, was not used by Hydro One in planning its investments, and exaggerated the benefit of capital investments.

Hydro One's Reliability Risk Model (RRM) was developed for two purposes: to provide a method for demonstrating the value of sustaining investments to customers, and to provide a directional indicator to assess the effect on reliability of an investment portfolio. Staff saw the value in quantifying the benefits of capital spending in a way that

[29] Hydro One Argument-in-Chief, p. 33

will resonate with customers. However, staff submitted that the RRM does not achieve this goal.

Most parties stated that the reliability risk model had several flaws beyond those conceded by Hydro One. Some parties supported the approach but stated that the model requires additional work to provide meaningful results.

A number of parties also pointed out that the conclusions drawn by Ipsos Reid did not appear to be supported by the data presented in its report, in particular the customer preference for an outcome between Scenarios 2 and 3.

Most parties concluded that there was not sufficient information from the engagement and the reliability risk model to clearly establish customer needs and preferences as a justification for Hydro One's capital expenditures.

## Findings

Although Hydro One made a good effort to engage its customers prior to filing its application, the customer engagement process was started only two months before the application was filed. In fact, the final Ipsos Reid report was submitted about one month before the application was filed. Little change was made to Hydro One's TSP as a result of these customer consultations. Given the complexity of the TSP, the OEB does not agree with Hydro One's assertion in its reply submission that such a very short elapsed time did not detract from the quality of the TSP evidence.

In addition, given the practical limitations of the RRM described below, it is not obvious that the customers were able to relate the various levels of capital investment to actual system reliability since that relationship does not exist. All they would have been able to learn from this exercise is that the higher the level of capital investment, the lower the system reliability risk (not actual reliability).

The OEB agrees with some of the submissions that some of the information presented to the participants may have been misleading (e.g. not making a distinction between planned and unplanned outages[30], not clearly communicating the historical improvements in actual system reliability[31], and using the "without investment" scenario as a base case.[32])

The selection of the participants was a topic of discussion throughout this proceeding, particularly the lack of input from First Nations as well as direct or indirect input from

[30] AMPCO submission, p. 33 and BOMA submission, p. 14
[31] AMPCO submission, p.34
[32] AMPCO submission, p. 28

customers of LDC representatives. Regarding First Nations' input, Hydro One indicated that since a number of First Nations did participate in the current proceeding (the Anwaatin First Nations), First Nations would be invited to participate in future customer engagement processes. Regarding LDC end-use customers, who represent 92% of Hydro One's revenue, a number of suggestions were made to get their feedback in a practical fashion since direct involvement of all those customers in Hydro One's engagement process is obviously impractical and does not fall within Hydro One's direct accountability. Suggestions included Hydro One seeking input from LDC participants about the relevant outcome of their own customer engagement exercises.

The RRM is a new tool that Hydro One started using in early 2016. Although the model is not used to develop Hydro One's investment program, it is used to demonstrate, on a relative or directional basis, the change in system reliability risk as a result of a certain incremental level of investment. The model uses hazard curves which are based on asset demographics, not condition, and focuses on three investment categories; lines, transformers and breakers. As described above, the model results were a key focus in Hydro One's communication with its customers to demonstrate the benefits of its proposed investments.

There was considerable discussion during the oral hearing about the use of the model results. Hydro One explained that the model cannot be "back-tested" or calibrated using historical system reliability data, even if this data is weather-normalized. As a result, according to Hydro One, the model results cannot be expressed in terms of impact on actual system reliability.

In its Reply Argument, Hydro One stated that "The fact that this tool is not used to specifically pick and choose investments, but only provides a way to communicate relative outcomes does not mean that the tool does not have a valid purpose."[33]
The OEB agrees with this statement in that the model provides an estimate of the percentage reduction in reliability risk which corresponds to a certain incremental amount of capital investment. What the model does not tell us is whether this percentage reduction in reliability risk is worth the incremental capital investment. As a hypothetical example, would spending an incremental $100 million to achieve a 1% reduction in reliability risk be a good business proposition, particularly given that this 1% reduction in reliability risk cannot be translated into any measurable result such as system reliability? According to Hydro One, establishing a relationship between

[33] Hydro One Reply Argument, p. 49

reliability risk and actual reliability performance is not possible because actual reliability performance is also influenced by other external factors such as weather conditions.[34]

In summary, without some form of correlation between the model results and actual system reliability, it would be impossible to determine whether a certain reduction in reliability risk is worth a certain level of capital investment. The model may be used to directionally compare investment scenarios, but it cannot be used to predict the benefit of any given scenario in terms of reliability.

The OEB finds that Hydro One's customer engagement process was adequate in general. However, some improvements can be made in the following areas:

- The process should be started sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance.
- Hydro One should have discussions with LDCs to determine practical ways to seek some input from their end users to inform Hydro One's application.
- Hydro One should seek timely and meaningful input from First Nations representatives.
- The information presented to the customers should be unambiguous and easy to understand.

Regarding the RRM, the OEB finds that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. As expected, the Ipsos Reid report indicated that customers expect to see an improvement in actual reliability performance, not necessarily only a reduced reliability risk for the proposed level of investment.

Based on the above-noted shortcomings of both the customer engagement process and the RRM, the OEB does not place significant weight on the evidence associated with these elements and, therefore, will not rely on the outcome as reported by Hydro One as compelling evidence of customer support for the proposed level of capital expenditures.

## 4.3 CAPITAL EXPENDITURES

Hydro One's TSP describes the processes developed and employed by Hydro One to create its capital investment plans for its transmission business. The plan results in

[34] TR Vol. 5, p. 128

**Table 4-1**
**Transmission Capital Expenditures, 2012 – 2021**
**$ million**

| Investment Category | 4 year Historical Actual Expenditures | | | | Bridge Year | Test Year 1 | Test Year 2 | Forecast Expenditures | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2021 | 2022 |
| Sustaining | $ 389.3 | $ 480.0 | $ 621.3 | $ 694.3 | $ 724.3 | $ 776.8 | $ 842.1 | $ 825.7 | $ 915.2 | $ 1,118.1 |
| Development | $ 329.4 | $ 171.7 | $ 131.6 | $ 166.0 | $ 166.0 | $ 196.4 | $ 170.2 | $ 244.0 | $ 254.0 | $ 258.3 |
| Operations | $ 15.2 | $ 17.7 | $ 28.4 | $ 15.6 | $ 30.1 | $ 25.4 | $ 30.8 | $ 58.8 | $ 21.1 | $ 24.7 |
| Common Corporate Costs | $ 42.1 | $ 49.1 | $ 63.4 | $ 67.1 | $ 83.5 | $ 77.6 | $ 79.1 | $ 79.1 | $ 78.2 | $ 73.8 |
| **Total** | $ 776.0 | $ 718.5 | $ 844.7 | $ 943.0 | $1,003.9 | $1,076.2 | $1,122.2 | $1,207.6 | $1,268.5 | $ 1,474.9 |

Source: Exhibit B1/Tab3/Schedule 1/p.1

The Sustaining category of investments is both the largest contributor to the capital budget and the category that shows the largest increase over historical (2012 – 2016) spending levels.

**Table 4-2**
**Transmission Capital Expenditures, 2017 – 2018**
**$ million**

| Investment Category | Candidate Investments | | Optimization | | Internal Stakeholder Engagement | | Executive Approval | |
|---|---|---|---|---|---|---|---|---|
| Timeline | February 25 - March 3, 2017 | | March 11-14, 2017 | | March 17 - April 14, 2017 | | April 19, 2017 | |
| | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 | 2018 |
| Sustaining | $ 934 | $ 1,003 | $ 748 | $ 847 | $ 777 | $ 842 | $ 777 | $ 842 |
| Development | $ 187 | $ 186 | $ 177 | $ 164 | $ 196 | $ 170 | $ 196 | $ 170 |
| Operations | $ 28 | $ 37 | $ 25 | $ 31 | $ 25 | $ 31 | $ 25 | $ 31 |
| Common Corporate Costs | $ 73 | $ 80 | $ 73 | $ 84 | $ 74 | $ 74 | $ 74 | $ 74 |
| Other | $ 4 | $ 5 | $ 4 | $ 5 | $ 4 | $ 5 | $ 4 | $ 5 |
| **Total** | $ 1,226 | $ 1,311 | $ 1,027 | $ 1,131 | $ 1,076 | $ 1,122 | $ 1,076 | $ 1,122 |

Source: Exhibit J2.7, Table 1

## Sustaining Capital Spending

Hydro One's evidence indicated that the Sustaining capital expenditures included in the application are required for Hydro One to meet its business objectives, including mitigating reliability risk and maintaining reliability in a safe manner to its customers. Other factors are decisions made to ensure compliance with regulatory, environmental and reliability standards and employee safety concerns. In addition, where feasible, asset life is extended through maintenance programs to avoid larger capital replacement costs.

Hydro One manages its Sustaining capital program by dividing the expenditures into two major categories:

- Stations, about 75% of the Sustaining capital budget, which represents the work required to refurbish or replace existing assets located within transmission stations, including existing protection, control, and telecommunication assets.

- Lines, about 25% of the budget, which is work required to refurbish or replace existing assets associated with overhead and underground transmission lines.

As shown in Table 4-3, the overall Sustaining capital requirements for the test year 2017 have increased by 7% over projected spending in the bridge year 2016. The Sustaining capital requirements for 2018 are approximately 8% higher than the 2017 requirements.

**Table 4-3**
**Sustaining Capital ($ Millions)**
**2012 – 2018**

| Description | Historic Years | | | | Bridge Year | Test Years | |
|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| **Stations** | $ 322.5 | $ 355.3 | $ 481.3 | $ 565.8 | $ 552.2 | $ 537.5 | $ 496.2 |
| **Lines** | $ 66.8 | $ 124.8 | $ 140.0 | $ 128.4 | $ 172.2 | $ 239.3 | $ 345.9 |
| **Total** | $ 389.3 | $ 480.0 | $ 621.3 | $ 694.3 | $ 724.3 | $ 776.8 | $ 842.1 |

Source: Exhibit D1/Tab4/Schedule 1, December 2, 2016 Update

## Stations

The overall stations sustaining capital expenditures for the test year 2017 are approximately 2.7% less than the projected spending in 2016. The spending requirements for 2018 are also approximately 7.7% less than 2017 requirements. Over 80% of the stations investment is proposed to be for integrated stations.[39]

[39] Exhibit B1/Tab 3/Schedule 2, Table 2

# 5.0 PRODUCTIVITY IMPROVEMENTS AND PERFORMANCE SCORECARD

Hydro One’s application included its proposed performance scorecard that is designed to track its performance in areas directly tied to its own business objectives, and are aligned with the objectives of the RRF.

Hydro One indicated that the metrics contained in the scorecard will provide the OEB and stakeholders visibility into how the company performs in a variety of areas, including cost control. The proposed scorecard included 22 specific metrics grouped across the four main RRF principles: Customer Focus, Operational Effectiveness, Policy Response and Financial Performance.[49]

In addition, Hydro One also indicated that as part of its scorecard development process, it also evaluated the use of Key Performance Indicators (KPIs) in measuring its performance. This followed a recommendation in the Benchmarking study to develop more robust KPIs to facilitate performance management.

Hydro One indicated that it would continue to develop a performance management system in which KPIs are aligned with the OEB scorecard and its business objectives to drive cost reductions and productivity improvement. It maintained that it is in the process of considering a variety of incremental metrics, and supporting systems that will increase the measurability of outcomes and identify the required changes to processes and activities to enhance productivity, reliability, customer service, customer satisfaction and other deliverables.

In its selection of KPIs, Hydro One identified two tiered sets of lower-level drivers of the top level metrics that were included in the proposed transmission scorecard.[50] Tier 2 metrics were identified as primary drivers of scorecard metrics and outcomes. Tier 3 metrics are measured at an additional level of granularity and focus on secondary drivers of the top level metrics. Hydro One maintained that the identification of these drivers of scorecard performance will allow it to recognize trends and identify and investigate underlying reasons for changes in the scorecard metrics.

As part of its scorecard evidence, Hydro One included a summary of its efforts to improve the efficiency of its organization and the productivity of its work programs. It maintained that it has begun to see the results of these efforts in its work programs and

[49] Exhibit B2/Tab 1/Schedule 1/Table 1
[50] Exhibit B2/Tab 1/Schedule 1/Table 2

budgets. For example, it highlighted that it has been able to maintain transmission OM&A at steady levels over recent years, despite factors putting upward pressure on OM&A costs.[51]

## Findings

The OEB first implemented the use of scorecards as a component of its RRF when it developed a generic scorecard to be used by all regulated distributors. The use of a generic scorecard facilitates performance monitoring and benchmarking. For transmitters, the OEB more recently established its expectations regarding scorecards in its filing guidelines for transmission applications to the OEB.

The filing guidelines contain the expectation that transmitters will propose scorecards that reflect their individual business realities and that can be used to measure and monitor performance and, where appropriate, enable comparisons among transmitters.

Hydro One is seeking “approval” of its proposed scorecard. The OEB does not consider it necessary that Hydro One have an approved scorecard at this time. The OEB notes that Hydro One has indicated that it will continue to develop a performance management system and finds that Hydro One should include the OEB’s determinations that follow to further evolve its scorecard in concert with the further development of its performance management system. The OEB expects Hydro One to propose an evolved scorecard in its next transmission rate application.

Hydro One has provided its analysis of how its proposed transmission business scorecard and key performance indicators align its business interests with those of its customers. In that respect Hydro One has met the expectations of the filing requirements. Hydro One’s proposal is detailed, well-articulated and transparent. The following determinations are to inform Hydro One’s continued scorecard development.

In the area of customer satisfaction, the OEB has provided its findings on Hydro One’s customer engagement initiatives. Hydro One should develop performance indicators that better reflect the satisfaction level of the ultimate end use customer. The OEB does not consider the satisfaction level of directly connected local distributors to be indicative of their customers’ level of satisfaction. Local distributors do not necessarily represent the interests of their customers on transmission issues nor do they suffer the same negative consequences if transmission service levels are poor.

Hydro One, as a corporate entity, has 1.3 million distribution customers. Hydro One should improve its internal institutional processes to better inform the transmission

[51] Exhibit B2/Tab 1/Schedule 1/p. 11

performance management system of its distribution customers' satisfaction level for the purpose of gauging what, if any, elements of transmission operation are the cause of any dissatisfaction.

With respect to operational effectiveness, the OEB finds Hydro One's proposed Cost Control measures to be appropriate as the ratios proposed will provide meaningful measures of relative quantitative benchmarks that can be monitored over time. However, the measures proposed for asset management could potentially run counter to the cost control performance indicators. The asset management measures are directly linked to Hydro One's budget and "OEB-approved plan". It is important to note that the OEB does not approve capital plans, but rather a capital envelope which provides an input to the revenue requirement which in turn determines the approved rates. The capital plans that underpin the submitted revenue requirement in an application are intended to illustrate the need for the submitted revenue requirement on a prospective basis. In other words, the plan is provided to facilitate consideration of the reasonableness of the requested revenues.

In this Decision, the OEB has directed Hydro One to provide a report on the execution of its capital plan. The purpose of the report is to demonstrate that its planning process is robust and that it is capable of executing the plan. This report is to include rationale for any departure from the plan. Such rationale may include awareness that the plan is no longer considered economical. This awareness would be based on previously unknown situations, solutions or more generally, a change in the main drivers for the original plan. In other words, it becomes apparent that the execution of particular elements of the plan is no longer in the interest of the customer. The proposed scorecard does not encompass the potential for this eventuality and to the extent that this performance indicator drives employee compensation it has the potential to suppress the desired ongoing evaluation of the prospective plan. As the OEB has determined in this Decision, plan execution is important but it should not be driven by a performance indicator solely based on ensuring the level of spending originally considered reasonable is spent.

Asset management is at the core of Hydro One's business function. The OEB expects Hydro One to consider implementing broader Asset Management measures that are directly related to positive outcomes for its customers. For instance, performance measures related to improvements in Hydro One's asset diagnostics that enhance the accuracy of asset replacement schedules could result in direct benefits to customers.

With respect to Policy Response, the OEB does not consider Hydro One's proposed inclusion of North American Electricity Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) Standards to be aligned with the intent of this element of the OEB's Scorecard objectives. NERC and NPCC standards are established to ensure events that impact reliability are avoided and/or planned for on a contingency basis so as to avoid the degradation in reliability to the extent it is reasonable to do so. These standards are a mandatory requirement of Hydro One's transmission business that is subject to regulatory enforcement. From a customer's perspective the measure of reliability that results, in part, from compliance with these standards is already included in the context of Hydro One's proposed system reliability measures under the operational effectiveness element of the proposed scorecard.

Hydro One should consider expanding its policy response measures to include its initiatives related to the government's stated policy objectives on the development of a Smart Grid. The scorecard element of policy response should not be limited to purely quantitative measures. A qualitative assessment of Hydro One's response performance related to the policy objectives embedded in the government's smart grid initiatives is one example of the type of measure the OEB anticipates under this element of the scorecard.

The OEB recognizes Hydro One's efforts to improve its efficiency and productivity that have resulted in the leveling of OM&A costs over recent years. The OEB directs Hydro One to establish firm short and long term targets for productivity improvements and associated reduction in revenue requirements as a means to drive continuous improvement and improve its internal and external benchmarking standings. Hydro One should put more emphasis on including performance metrics in the scorecard that provide objective year-over-year unit cost measures of productivity, safety, reliability and quality of service improvements.

The OEB directs Hydro One to continue to develop its performance management system and scorecard to reflect the OEB's observations and determinations. Ultimately, the elements of the scorecard that directly relate to the customer experience should be customer facing and tied directly to the customer experience. Hydro One should consider the merits of implementing measures that reflect outcomes of Hydro One's overall business such as gross fixed assets/unit of load serving capacity to more fully illustrate its overall cost of service provision. The OEB directs Hydro One to provide its analysis of the merits of this and similar measures with its next scorecard submission.

# SEC INTERROGATORY #16

**Reference:**
TSP-01-04-14

**Interrogatory:**
With respect the BCG, Assessing Hydro One's Investment Planning Process – Final Report:

a) Please provide a copy of the retainer agreement between BCG and Hydro One.

b) Please provide a copy of the BGC work plan (or similar document).

c) Please provide a summary of all *other* work BCG has done for Hydro One in the last 5 years and the total cost of that work.

d) [p.3] Please provide a list of 'peer utilities' that BCG is comparing Hydro One to. Please provide the source o the information for these 'peer utilities'. [CHECK AGAINST APPENDIX]

e) [p.3, Exhibit 1] Please provide the 'Benchmarked peer group performance' score for each aspect to the planning process included in the exhibit. Is the amount the average or median peer performance of the peer group.

f) [p.9] Please explain what information BCG relied upon to review the planning processes of the peer utilities.

g) [p.9] Who is the ISO-55000 implementation expert and 'Former Ontario Energy Board panel member' that BCG consulted and for what purpose.

**Response:**

a) Please refer to Attachment 1. This engagement was not subject to an RFP. Hydro One has provided this agreement and the associated work plan in confidence per the terms of the agreement.

b) Please refer to Attachment 1.

c) Please refer to EB-2017-0049, Oral Hearing Undertakings J2.4 and J7.1. The total cost of transmission work performed by BCG over the past 5 years is approximately $6.7 million.

d) Please refer to Exhibit B-1-1 TSP Section 1.4 Attachment 14 Exhibit 2 on p 8
Please refer to part f) below.

e) Benchmarked peer group scores were based on BCG subjective assessment of the peers on each of the dimensions; number is median give nature of the exercise.

f) BCG leveraged a variety for sources, including but not limited to: Expert interviews, regulatory filings, BCG experience across utilities, and BCG experience around planning best practices across other industries.

g) The former OEB panel member was Karen Taylor; the purpose of the interview was to align on general context for the broader regulatory environment in Ontario, given how critical it is to how a utility operates.

BCG

November 13, 2017

Mr. Bruno Jesus
Director, Strategy & Integrated Planning
Hydro One Networks Inc.
483 Bay Street, North Tower, Toronto, ON M5G 2P5

**Re: BCG support for Investment planning process review**

Dear Bruno,

Thank you for the opportunity to support Hydro One Networks Inc. ("Hydro One") on its review of its investment planning process. This letter is meant to formalize and document BCG's proposal for project management support of the filing.

**Context of this effort**

Hydro One recently received a decision from the OEB on its 2017-2018 Transmission Revenue Requirement in which the OEB highlighted perceived weaknesses of several aspects of Hydro One's planning processes and required that Hydro One undertake an independent, third party assessment of its Transmission System Plan, including its asset condition assessment and capital planning processes. This report is a key deliverable for the upcoming 2019-2023 rate filing and will likely be crucial to Hydro One's ability to secure additional capital for system development and renewal in the coming years.

Prior to the OEB decision, Hydro One had recognized some of the challenges it faced in investment planning and conducted an internal assessment of its existing process, with the help of a BCG team, as part of the Good to Great program. In response to that assessment, Hydro One made a number of improvements to the planning process that were implemented in its 2018 cycle, which recently concluded as of November 2017. Describing the impact of these changes will be a critical component of the report to demonstrate to the OEB that Hydro One has been proactive in improving its process.

Developing this independent assessment will require a strong understanding of the evolution of Hydro One's planning process, including an ability to understand the scope of recent improvements and their expected impact on the next rate filing. We believe BCG is uniquely qualified to support in this effort given the depth of our experience in utility capital planning and our intimate knowledge of Hydro One's planning process given our involvement in the Good to Great program and in recently providing project management support for the 2019-2023 Transmission rate filing.

**Scope of work**

We propose to deliver a comprehensive assessment of Hydro One's Transmission System Plan, including:

- Assessment of investment planning process and the impact of recent improvements undertaken in the 2018 cycle as compared to prior years

- ☐ This will include benchmarking of Hydro One's processes against other major US and Canadian utilities
- ☐ Testimony before the OEB as to the findings of our assessment, as required, during the upcoming rate case for the 2019-2023 Transmission filing

1. ***Assessment of Hydro One's investment planning process***
   The primary deliverable will be a holistic assessment of Hydro One's revised investment planning process, including:
   - ☐ Reviewing Hydro One's legacy process and the results of its initial internal assessment of the need for improvement
   - ☐ Developing a framework to review and benchmark Hydro One's processes vs. past efforts and US and Canadian peers
   - ☐ Outlining the key steps Hydro One took to improve its process for 2018, and the impact of those improvements vs. prior years, including interviews with key stakeholders to understand day to day impacts of new process
   - ☐ Identifying further areas for continued improvement in future planning cycles

2. ***Testimony support***
   We commit to provide necessary support for written and oral testimony during Hydro One's upcoming 2019-2023 Transmission Revenue Requirement filing.

**Working arrangements**

This project will be led by Andrew Loh, David Gee and Justin Dean, Partners and Managing Directors at BCG. Julie Powers, Project Leader, will lead the day-to-day activities of the project with support from two consultants. Having contributed to the 2017-2018 Transmission filing and provided project management support for the 2019-2023 filing, Julie is uniquely positioned to continue to support Hydro One in this effort. The team will be supported by experts within BCG's Power & Utilities practice area.

We propose that support begin on November 27 and last for 6 weeks, with a two week pause from December 18-January 2 to accommodate the Christmas and New Year holidays. We would expect to deliver the report on January 19th, and would be available to provide continued support for preparation and delivery of oral testimony once the OEB hearing schedule is established. The weekly cost of this team for the six-week effort is [redacted]

If additional support is required during rate case testimony, we will charge [redacted] for up to two weeks of pre-testimony preparation and time on the witness stand [redacted] Per your request, this rate and team is completely independent of any other work that may be taking place elsewhere at Hydro one.

We look forward to having the opportunity to support Hydro One in this effort. It is clearly a critical effort to ensure Hydro One's continued success as a privatized enterprise.

Sincerely,

Andrew Loh
Partner and Managing Director

If you agree to the terms of the proposal laid out in this letter, please sign and date 2 copies and provide one back to us for our records:

Hydro One Networks Inc.

Per: ______________________ Nov 23/17

Bruno Jesus
Director, Strategy & Integrated Planning

Date

**Our standard terms**

The following are the standard terms under which BCG has for a long time successfully worked with our clients across the globe, and under which we agree to work together with you.

**Protecting Confidential Information**
As a condition of this proposal, the parties have entered into a confidentiality agreement dated November 17, 2017 and attached hereto as a Schedule, which confidentiality agreement is incorporated herein by reference. Included within this confidentiality obligation shall be any information we share with you regarding our pricing or rates.

Neither of us will make public, without the other's prior written approval,that we are working with each other.

**Safeguards for Companies in the Same Industry**
Serving multiple companies in the same industry allows us at BCG to deepen our industry knowledge and increases our ability to take an informed view of the strategic issues facing our clients. We maintain internal safeguards that enable us to work for clients in the same industry without

# UNDERTAKING - JT 1.11

**Reference:**
I-07-SEC-016, part c)

**Undertaking:**
To re-file previous undertakings, now un-redacting the previously redacted transmission related information.

**Response:**
Attachments 1 to 8 contain Hydro One's response to the undertakings J2.4 and J7.01 that were filed in the EB-2017-0049 proceeding. These attachments are also referenced in the interrogatory response, I-07-SEC-016 filed in the current proceeding. Certain portions of the attachments contain information that has been redacted with a red box or a black box as follows:

- Red box redactions contain information that relates to the unregulated business of Hydro One's affiliated companies and as such is not relevant and falls outside of the scope of the current proceeding. In the EB-2017-0049 proceeding, the Board considered the relevance of the red box redacted information and concluded that it has little probative value to the Board in assessing the ultimate proposal submitted by Hydro One in its application.

- Black box redactions contain information that was prepared in contemplation of Hydro One's 2017-2018 transmission rate application (EB-2016-0160). In most instances, the information contains plans, strategies, or considerations that were formulated in developing the 2017-2018 transmission rate application. It also contains historical information and values that have been reproduced in the current proceeding. The EB-2016-0160 proceeding has been adjudicated and the Board rendered its revised decision on November 1, 2017. As such, the information pertaining to the concluded proceeding is not relevant and has no probative value to the Board in assessing Hydro One's proposals that are subject of the current proceeding.

# Strategic Plan

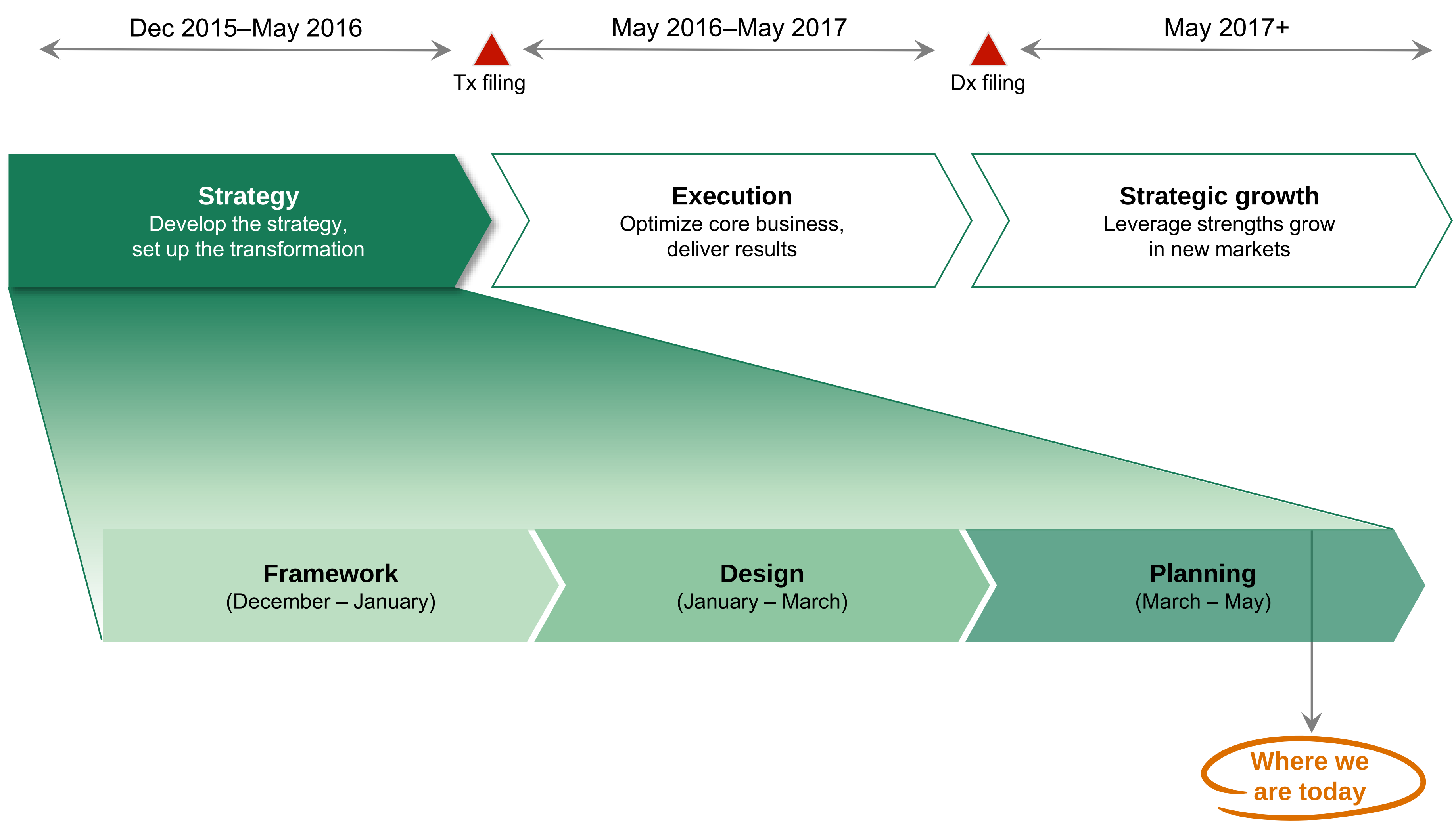
## Board of Directors discussion document

May 6, 2016

THE BOSTON CONSULTING GROUP

# Context: Where we are in the longer-term journey

Completing Planning in preparation for Execution



# Board meetings in 2016

## January 14

**Review strategic framework**
- Baseline trajectory
- Strategic framework
- Strawman strategy and transformation sequence
- Plan to finalize strategy and launch transformation

## March 31

**Review draft of strategy**
- Voice of customer
- System investment plan
- Capital delivery strategy
- Customer service roadmap
- Efficiency opportunity scaling

**Confirm direction of Tx filing**
- Investment plan and supporting evidence
- Customer input
- Bill impact

**For education**
- [redacted]

## May 6 (Today)

**Approve**
- 5-year strategy

**Review**
- Top-down 5 year financials
- 2-year Tx filing ('17-'18)
- Initial perspectives on 2017 Dx filing & selected strategic choices
- Core capabilities for T&D operators
- Good to Great execution plan

**For education:**
- [redacted]

## August 12

**Update on Good to Great execution**

**For education:**
- [redacted]

## December 2

**Approve**
- 6 year business plan (2017-22)
- Budget (2017)

**Review of 2018-22 Dx filing**

**Review IT strategy**

**Update on Good to Great execution**

**For education:**
- [redacted]

57

# Our agenda for today

| Topic | Lead | Time (min) |
|---|---|---|
| **Opening** | *Mayo Schmidt* | 5 |
| **Overall strategic narrative** | *Mayo Schmidt* | 30 |
| **Deep dive topics** | | |
| • Top down 5 year financials | *Mike Vels* | 30 |
| • Tx filing | *Oded Hubert / Mike Penstone* | 30 |
| • Dx filing | *Oded Hubert / Mike Penstone* | 20 |
| • Capabilities | *Mayo Schmidt* | 20 |
| • Good to Great execution plan | *Stefanie Stocco* | 10 |
| **Closing and next steps** | *Mayo Schmidt* | 5 |

# Overall strategic narrative (I)

**Since privatization, Hydro One has embarked on a journey to becoming a best-in-class, customer-centric commercial organization. This is consistent with the 4 core principles of the RRFE[1]**

- Customer focus: Responding to the needs and preferences of customers
- Operational effectiveness: Meeting reliability and quality objectives while continuously driving productivity
- Public policy responsiveness: Delivering on obligations mandated by government
- Financial performance: Maintaining financial viability, sustaining operational effectiveness efforts



**Our strategy translates these principles into our approach to**

- Serving our customers
- Forming our investment plans (for approval in rate filings)
- Operating and managing the costs of our business

**…while maintaining our strong commitment to Safety and the Environment**

**Serving our customers: Improving the end-to-end customer experience and satisfaction by addressing the unique needs of our four core segments. In the near-term we will focus on:**

- Residential/Small Business: Improving first-call resolution, enhancing digital experience, redesigning the bill
- Commercial & Industrial: Marketing energy conservation programs, improving first-call resolution
- Large Distribution: Marketing energy conservation programs, better communicating unplanned outages
- Transmission: Pro-active reporting on power quality and reliability, following through on commitments made

1. Renewed Regulatory Framework for Electricity

# Overall strategic narrative (II)

**Forming investment plans: Be responsible stewards of assets while taking a customer-centric approach**

- Transmission: Sustain assets to meet reliability, risk, and power quality needs of customers
- Distribution: Transition to a modern, reliable grid through condition-based asset renewal and targeted enhancement programs to increase reliability and functionality with highest return on investment

**Investment plans will be presented in 3 rate filings, each with unique objectives to consider:**

- 2-year Transmission filing (May 2016):
  - Signal longer-term capital plan (5 year plan weighted to out-years, based on risk modeling)
  - Shift to RRFE[1] principles (e.g. consult with customers, incorporate productivity commitment)
- 5-year Distribution filing (May 2017):
  - Assess range of investment options through customer consultation
  - Align on incentive rate structure based on capital flexibility and fair distribution of productivity incentives
- 5-year Transmission filing (May 2018):
  - Secure investment plan previewed in May 2016 submission and replicate
  - Replicate incentive rate structure established in Distribution the prior year

**Operating and managing the costs of our business: Set efficiency targets informed by benchmarks and track through a performance management system**

- Efficiency program launched to both offset customer bill impacts and capture productivity benefits
- Unconstrained potential of ~$200M (~50/50 OM&A vs. capital) with varying degrees of difficulty to capture
- Execution already underway to build early momentum and drive impact near-term

1. Renewed regulatory framework for electricity

# Overall strategic narrative (III)

**Our strategy effectively balances shareholder returns and rate payer impacts over the next 5 years**

- Total capital expected to grow to ~$2B+ by 2021, resulting in rate base of ~$22B (~5-6% growth)
- OM&A expected to remain flat to 2021, with cost pressures (e.g. inflation) offset by efficiency program impacts
- Range of scenarios possible, depending on investment plan approval and efficiency potential realized
- Implies [redacted] TSR and annual tariff increases of 2-3% for Distribution and 5-6% for Transmission

**As we continue our transition to a high performing culture, we have identified 10 core capabilities to successfully deliver on this plan and prepare us for future growth**

61

- Aspire to be best-in-class in 3 of them: customer service, regulatory, asset management
- While still early, already down path of developing and embedding improvements across 10 core capabilities
- Assessment, development and acquisition of talent remains a critical focus

**Achieving excellence in these areas prepares and earns us the right to grow beyond our core business**

[redacted]

# UNDERTAKING - JT 1.24

**Reference:**
I-07-SEC-036

**Undertaking:**
To provide actuals for the table in SEC IR 36 under the column EB-2019-0018.

**Response:**

Please refer to the updated interrogatory I-07-SEC-036 provided as Attachment 1 which includes 2016 actuals as well as updated actual and forecast expenditures for the station centric assets (transformers, breakers and protection systems) for 2017-2022.

Furthermore, historical replacement units have been updated to reflect a correction to actuals reported. For 2018 this was due to a lag in reporting of in-serviced units that were not accounted for when the Application was filed on March 19, 2019.

To provide consistency, Table 3 and 4 from Exhibit B-1-1 TSP Section 3.3 showing the replacement units have been updated to reflect unit updates provided in this undertaking J1.24 (I-7-SEC-36) and undertaking J1.26 (I-12-AMPCO-28)

**Table 1: Asset Replacement Rates - Transmission Station Assets**

| | Historical | | | | Bridge | Test | | | Plan | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
| **Transformer Portfolio** | | | | | | | | | | |
| # of Replacements | 24* | 18* | 15 | 28* | 20 | 9 | 23 | 19 | 40 | 17 |
| % of Fleet | 3.3% | 2.6% | 2.1% | 3.6% | 2.8% | 1.3% | 3.2% | 2.7% | 5.6% | 2.4% |
| **Circuit Breaker Portfolio** | | | | | | | | | | |
| # of Replacements | 31 | 73 | 108 | 155* | 88 | 135 | 105 | 88 | 215 | 95 |
| % of Fleet | 0.7% | 1.6% | 2.4% | 3.2% | 1.9% | 2.8% | 2.2% | 1.9% | 4.5% | 2.0% |
| **Protection Systems Portfolio** | | | | | | | | | | |
| # of Protection Replacements | 445 | 627 | 298 | 325* | 453 | 465 | 370 | 503 | 681 | 384 |
| % of Fleet | 3.6% | 5.1% | 2.5% | 2.6% | 3.6% | 3.7% | 3.0% | 4.0% | 5.4% | 3.1% |

Witness: Donna Jablonsky

**Table 2: Asset Replacement Rates - Transmission Line Assets**

| | Historical | | | | Bridge | Test | | | Plan | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** |
| **Conductor Portfolio** | | | | | | | | | | |
| kms of Circuit Replacements | 201 | 183 | 119 | 51 | 140 | 64 | 483 | 795 | 309 | 475 |
| % of Fleet | 0.7% | 0.6% | 0.4% | 0.2% | 0.5% | 0.2% | 1.7% | 2.7% | 1.1% | 1.6% |
| **Wood Pole Portfolio** | | | | | | | | | | |
| # of Replacements | 845 | 761* | 966* | 735* | 560 | 800 | 800 | 800 | 800 | 800 |
| % of Fleet | 2.0% | 1.8% | 2.3% | 1.8% | 1.3% | 1.9% | 1.9% | 1.9% | 1.9% | 1.9% |
| **Steel Structure Portfolio** | | | | | | | | | | |
| # of Renewal | 371* | 86* | 725 | 1050 | 220 | 260 | 500 | 500 | 500 | 500 |
| % of Fleet | 0.7% | 0.2% | 1.4% | 2.0% | 0.4% | 0.5% | 1.0% | 1.0% | 1.0% | 1.0% |
| **Insulator Portfolio** | | | | | | | | | | |
| # of circuit structures | 155 | 2100 | 3623* | 3958* | 3700 | 3700 | 3700 | 3450 | 3450 | 3450 |
| % of Fleet | 0.1% | 1.4% | 2.6% | 3.1% | 2.9% | 2.9% | 2.9% | 2.7% | 2.7% | 2.7% |
| **Underground Cable Portfolio** | | | | | | | | | | |
| Kms of Circuit Replacements | 0 | 2.3* | 0 | 0 | 4.7 | 0 | 0 | 0 | 0 | 7.2 |
| % of Fleet | 0% | 0.9% | 0% | 0% | 1.8% | 0% | 0% | 0% | 0% | 2.7% |

**Replacements and percentage of fleet figures have been updated to reflect a correction to historical actuals. The 2017 and 2018 insulator figures reflect COB, CP and polymer insulator replacements.*

**SEC-36**

Please fill in the shadded cells

| | EB-2016-0160 Application/Proposal (1) | | | | | EB-2016-0160 DR0** | | EB-2019-0082 | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2014A | 2015A | 2016F | 2017F | 2018F | 2017F | 2018F | 2016A | 2017A | 2018A | 2019F | 2020F | 2021F | 2022F |
| **Transformer Portfolio** | | | | | | | | | | | | | | |
| # Replacements | 24 | 24 | 19 | 27 | 22 | 27 | 22 | 18 | 15 | 28[+] | 20 | 9 | 23 | 19 |
| % of Fleet | 3.3% | 3.3% | 2.6% | 3.7% | 3.1% | 3.7% | 3.1% | 2.5% | 2.1% | 3.6%[+] | 2.8% | 1.3% | 3.2% | 2.7% |
| Capital ($M) *** | 132.0 | 132.0 | 104.5 | 148.5 | 121.0 | 148.5 | 121.0 | 77.3 | 75.7 | 193.6 | 110.3 | 50.6 | 131.9 | 111.1 |
| | | | | | | | | | | | | | | |
| **Circuit Breaker Portfolio** | | | | | | | | | | | | | | |
| # Replacements | 83 | 31 | 43 | 66 | 132 | 66 | 132 | 73 | 108 | 155[+] | 88 | 135 | 105 | 88 |
| % of Fleet | 1.8% | 0.7% | 0.9% | 1.5% | 2.9% | 1.5% | 2.9% | 1.5% | 2.4% | 3.2%[+] | 1.9% | 2.8% | 2.2% | 1.9% |
| Capital ($M) *** | 58.1 | 21.7 | 30.1 | 46.2 | 92.4 | 46.2 | 92.4 | 42.4 | 54.7 | 77.9 | 47.5 | 74.3 | 58.9 | 50.3 |
| | | | | | | | | | | | | | | |
| **Protection Systems Portfolio** | | | | | | | | | | | | | | |
| # Replacements | 610 | 266 | 367 | 449 | 528 | 449 | 528 | 627 | 298 | 325[+] | 453 | 465 | 370 | 503 |
| % of Fleet | 5.0% | 2.2% | 3.0% | 3.7% | 4.4% | 3.7% | 4.4% | 5.1% | 2.5% | 2.6%[+] | 3.6% | 3.7% | 3.0% | 4.0% |
| Capital ($M) *** | 76.3 | 33.3 | 45.9 | 56.1 | 66.0 | 56.1 | 66.0 | 57.3 | 42.8 | 60.5 | 64.7 | 67.8 | 54.9 | 76.2 |
| | | | | | | | | | | | | | | |
| **Conductor Portfolio** | | | | | | | | | | | | | | |
| Replacements (km) | 93 | 201 | 183 | 192 | 440 | 192 | 440 | 183 | 119 | 51 | 140 | 64 | 483 | 795 |
| % of Fleet | 0.3% | 0.7% | 0.6% | 0.6% | 1.5% | 0.6% | 1.5% | 0.6% | 0.4% | 0.2% | 0.5% | 0.2% | 1.7% | 2.7% |
| Capital ($M) | 40.7 | 58.4 | 76.9 | 67.1 | 143.1 | 67.1 | 143.1 | 68.0 | 36.5 | 52.0 | 137.6 | 150.8 | 191.4 | 211.7 |
| | | | | | | | | | | | | | | |
| **Wood Pole Portfolio** | | | | | | | | | | | | | | |
| # Replacements | 897 | 845 | 850 | 850 | 850 | 935 | 850 | 761 | 966 | 735 | 560 | 800 | 800 | 800 |
| % of Fleet | 2.2% | 2.0% | 2.0% | 2.0% | 2.0% | 2.2% | 2.0% | 1.8% | 2.3% | 1.8% | 1.3% | 1.9% | 1.9% | 1.9% |
| Capital ($M) | 43.6 | 38.5 | 38.3 | 35.3 | 35.3 | 38.8 | 33.9 | 42.8 | 41.2 | 35.3 | 34.8 | 51.0 | 52.0 | 53.0 |
| | | | | | | | | | | | | | | |
| **Steel Structure Portfolio**[++] | | | | | | | | | | | | | | |
| # Renewal | 153[++] | 371[++] | 462 | 1250 | 1600 | 1145 | 1600 | 86 | 725 | 1050 | 220 | 260 | 500 | 500 |
| % of Fleet | 0.3% | 0.7% | 0.9% | 2.4% | 3.1% | 2.2% | 3.0% | 0.2% | 1.4% | 2.0% | 0.4% | 0.5% | 1.0% | 1.0% |
| Capital ($M) | 3.8 | 5.1 | 8.8 | 42.5 | 54.4 | 39.0 | 26.2 | 2.3 | 42.1 | 37.7 | 9.3 | 11.4 | 21.8 | 22.3 |
| | | | | | | | | | | | | | | |
| **Underground Cable Portfolio** | | | | | | | | | | | | | | |
| Replacements (km) | 3.1 | 0 | 0 | 0 | 4.8 | 0 | 4.8 | 2.3 | 0 | 0 | 4.7* | 0 | 0 | 0 |
| % of Fleet | 1.1% | 0.0% | 0.0% | 0.0% | 1.8% | 0.0% | 1.8% | 0.9% | 0.0% | 0.0% | 1.8% | 0.0% | 0.0% | 0.0% |
| Capital ($M) | 20.6 | 3.5 | 1.4 | 2.3 | 22.5 | 2.3 | 22.5 | 1.7[+++] | 10.7 | 16.5 | 15.0 | 7.1 | 32.5 | 33.6 |

*Source: (1) EB-2016-0160 I-6-20*

* Discrepancy is due to rounding

** EB-2016-0160 DRO Forecast reflects EB-2016-0160 Application/Proposal due to timing of Decision & Order. Revised units were not forecast as part of the DRO submission.

*** 2016A, 2017A and 2018A Capital expenditures reflect capitalized costs for station centric asset replacements (transformers, breakers and protection systems). Forecasts for 2019F and onwards reflect the 2016-2018A average cost including CPI (Exhibit B-1-1 TSP Section 2.1 page 11)

[+] Updated to reflect 2018 in-serviced units that were not accounted for, due to a lag in reporting, when the Application was filed

[++] Updated values to reflect correct accomplishments for 2014, 2015

[+++] Replacement cost included under a development project; not in the sustainment category

| | 2016-2018 Forecast | | | 2016-2018 Actuals | | | Forecast | Actuals | Forecast | Actuals |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2016 | 2017 | 2018 | 2016-2018 | 2016-2018 | 2017-2018 | 2017-2018 |
| **Transformer Portfolio** | | | | | | | | | | |
| # Replacements | 19 | 27 | 22 | 18 | 15 | 28 | 68 | 61 | 49 | 43 |
| Capital ($M) | 104.5 | 148.5 | 121 | 77.3 | 75.7 | 193.6 | 374.0 | 346.6 | 269.5 | 269.4 |
| $M/# Replacement | 5.500 | 5.500 | 5.500 | 4.292 | 5.048 | 6.916 | 5.500 | 5.682 | 5.500 | 6.264 |
| | | | | | | | | | | |
| **Circuit Breaker Portfolio** | | | | | | | | | | |
| # Replacements | 43 | 66 | 132 | 73 | 108 | 155 | 241 | 336 | 198 | 263 |
| Capital ($M) | 30.1 | 46.2 | 92.4 | 42.4 | 54.7 | 77.9 | 168.7 | 175.0 | 138.6 | 132.6 |
| $M/# Replacement | 0.700 | 0.700 | 0.700 | 0.581 | 0.506 | 0.503 | 0.700 | 0.521 | 0.700 | 0.504 |
| | | | | | | | | | | |
| **Protection Systems Portfolio** | | | | | | | | | | |
| # Replacements | 367 | 449 | 528 | 627 | 298 | 325 | 1344 | 1250 | 977 | 623 |
| Capital ($M) | 45.875 | 56.125 | 66 | 57.3 | 42.8 | 60.5 | 168.0 | 160.5 | 122.1 | 103.3 |
| $M/# Replacement | 0.125 | 0.125 | 0.125 | 0.091 | 0.144 | 0.186 | 0.125 | 0.128 | 0.125 | 0.166 |
| | | | | | | | | | | |
| **Conductor Portfolio** | | | | | | | | | | |
| Replacements (km) | 183 | 192 | 440 | 183 | 119 | 51 | 815 | 353 | 632 | 170 |
| Capital ($M) | 76.9 | 67.1 | 143.1 | 68 | 36.5 | 52 | 287.1 | 156.5 | 210.2 | 88.5 |
| $M/# Replacement | 0.420 | 0.349 | 0.325 | 0.372 | 0.307 | 1.020 | 0.352 | 0.443 | 0.333 | 0.521 |
| | | | | | | | | | | |
| **Wood Pole Portfolio** | | | | | | | | | | |
| # Replacements | 850 | 935 | 850 | 761 | 966 | 735 | 2635 | 2462 | 1785 | 1701 |
| Capital ($M) | 38.3 | 38.8 | 34 | 42.8 | 41.2 | 35.3 | 111.0 | 119.3 | 72.7 | 76.5 |
| $M/# Replacement | 0.045 | 0.041 | 0.040 | 0.056 | 0.043 | 0.048 | 0.042 | 0.048 | 0.041 | 0.045 |
| | | | | | | | | | | |
| **Steel Structure Portfolio**[++] | | | | | | | | | | |
| # Renewal | 462 | 1145 | 1600 | 86 | 725 | 1050 | 3207 | 1861 | 2745 | 1775 |
| Capital ($M) | 8.8 | 39 | 26 | 2.3 | 42.1 | 37.7 | 74.0 | 82.1 | 65.2 | 79.8 |
| $M/# Replacement | 0.019 | 0.034 | 0.016 | 0.027 | 0.058 | 0.036 | 0.023 | 0.044 | 0.024 | 0.045 |
| | | | | | | | | | | |
| **Underground Cable Portfolio** | | | | | | | | | | |
| Replacements (km) | 0 | 0 | 4.8 | 2.3 | 0 | 0 | 4.8 | 2.3 | 4.8 | 0 |
| Capital ($M) | 1.4 | 2.3 | 23 | 1.7 | 10.7 | 16.5 | 26.2 | 27.2 | 24.8 | 27.2 |
| $M/# Replacement | #DIV/0! | #DIV/0! | 4.688 | 0.739 | #DIV/0! | #DIV/0! | 5.458 | 11.826 | 5.167 | #DIV/0! |

Source: 2016-2018 Data from JT1.24

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Beck #1 SS
**Targeted Start Date:** Q2 2017
**Targeted In-service Date:** Q4 2019
**Targeted Outcome:** *Customer Focus, Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Beck#1 SS that are in need of replacement due to deteriorated condition, equipment performance, and obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Sir Adam Beck #1 SS is a switching station connecting Ontario Power Generation's ("OPG's") Sir Adam Beck Generating Station I to the 115kV transmission system. The facility was originally placed in-service in 1947 and many of the station assets are in need of major work to maintain reliability. The existing 115kV bus at Beck #1 SS is also currently restricting generation output and will require upgrading to higher capacity to remove these restrictions.

There are two ABCBs at Sir Adam Beck #1 SS that are up to 44 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable than a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Beck#1 SS.

This project entails:

- Replacement of two ABCBs, associated breaker disconnect switches, station DC systems;
- Upgrades to the station's 115kV bus to remove capacity restrictions and protection and control equipment; and
- Removal of four free standing transformers along with the entire high pressure air system, which will no longer be required.

Witness: Chong Kiat (CK) Ng

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

**Alternatives:**
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs of projects of similar scope.

**Outcome:**
To maintain system reliability and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 6.4 | 12.9 | 25.9 |
| Operations, Maintenance & Administration and Removals | (0.5) | (0.9) | (1.8) |
| **Gross Investment Cost** | **5.9** | **12.0** | **24.1** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **5.9** | **12.0** | **24.1** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Beck #2 TS
**Targeted Start Date:** Q1 2016
**Targeted In-Service Date:** Q4 2021
**Targeted Outcome:** *Customer Focus, Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Beck#2 TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Sir Adam Beck #2 TS is a critical network station connecting Ontario Power Generation's ("OPG's") Sir Adam Beck Generating Station II to the 230kV transmission system. The facility was originally placed in-service in 1955 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are twenty ABCBs at Sir Adam Beck #2 TS that are up to 48 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Beck#2 TS.

This project entails:

- Replacement of twenty ABCBs, associated breaker disconnect switches, station AC/DC systems;
- Upgrades to protection and control equipment needed to meet NPCC standards; and
- Removal of forty sets of free standing transformers, along with the entire high pressure air system which will no longer be required.

Witness: Chong Kiat (CK) Ng

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

**Alternatives:**
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on detailed cost estimates prepared by Hydro One.

**Outcome:**
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 30.4 | 15.4 | 93.4 |
| Operations, Maintenance & Administration and Removals | (0.6) | (0.5) | (2.7) |
| **Gross Investment Cost** | **29.8** | **14.9** | **90.7** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Capital Investment Cost** | **29.8** | **14.9** | **90.7** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

**Hydro One Networks – Investment Summary Document**
***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Bruce A TS
**Targeted Start Date:** Q4 2013
**Targeted In-Service Date:** Q2 2019
**Targeted Outcome:** *Customer Focus, Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Bruce A TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Bruce A TS is a critical network station connecting the Bruce Power Nuclear Generation Station to the 500kV and 230kV transmission network. The Bruce A TS 230 kV switchyard was originally placed in-service in the 1976 and many of the station assets are in need of major work to sustain their functionality. The existing breakers and strain buses are also restricting generation in the area due to their limited short circuit capability. Due to the stations criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are sixteen 230kV ABCBs at Bruce A TS that are 44 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Bruce A TS.

This project entails:

- Replacement of sixteen circuit breakers, associated breaker disconnect switches, instrument transformers, protection and control systems, and other associated auxiliary components; and
- Removal of thirty-two sets of free standing transformers along with the high pressure air system which will no longer be required.

To address the short circuit interrupting capability the station strain buses will be uprated and supporting structures will be reinforced or replaced, as required, to withstand the mechanical and thermal effects of the higher short circuit current.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

**Alternatives:**
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on detailed cost estimates prepared by Hydro One.

**Outcome:**
To eliminate operational risks associated with operating end of life equipment, address the insufficient short circuit capability, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 13.8 | 19.7 | 105.9 |
| Operations, Maintenance & Administration and Removals | 0.0 | 0.0 | (1.0) |
| **Gross Investment Cost** | **13.8** | **19.7** | **104.9** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **13.8** | **19.7** | **104.9** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Bruce B SS
**Targeted Start Date:** Q2 2017
**Targeted In-service Date:** Q4 2020
**Targeted Outcome:** *Customer Focus, Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Bruce B SS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Bruce B SS is a critical network station connecting the Bruce Power Nuclear Generation Station to the 500kV transmission network. The Bruce B SS 500kV switchyard was originally placed in-service in the 1981 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are ten 500kV ABCBs at Bruce B SS that are 37 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Bruce B SS.

This project entails:

- Replacement of ten 500kV ABCBs, associated disconnect switches, and protection and control equipment needed to meet NPCC standards; and
- Removal of twenty sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Witness: Chong Kiat (CK) Ng

**Alternatives:**
Two alternatives were considered:
- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

**Outcome:**
To eliminate operational risks associated with end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 1.0 | 26.4 | 70.1 |
| Operations, Maintenance & Administration and Removals | (0.1) | (1.8) | (4.9) |
| **Gross Investment Cost** | **0.9** | **24.6** | **65.2** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **0.9** | **24.6** | **65.2** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Cherrywood TS 230 KV
**Targeted Start Date:** Q4 2018
**Targeted In-service Date:** Q4 2020
**Targeted Outcome:** *Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Cherrywood TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Cherrywood TS is a critical network station connecting the Ontario Power Generation's ("OPGs") Pickering Nuclear Generating Station as well as a considerable portion of the output of OPG's Darlington Nuclear Generating Station to the 500kV and 230kV transmission network. The facility was originally placed in-service in 1969 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Cherrywood TS.

This project entails:

- Replacement of twelve ABCBs, associated breaker disconnect switches, station AC & DC systems as well as protection and control equipment needed to meet NPCC standards; and
- Removal of twenty-four sets of free standing transformers along with portions of the high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Witness: Chong Kiat (CK) Ng

**Alternatives:**
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on budgetary estimates prepared by Hydro One utilizing historical costs for projects of similar scope.

**Outcome:**
To reduce operational risks associated with the operation of end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers.

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 1.5 | 4.1 | 65.1 |
| Operations, Maintenance & Administration and Removals | (0.1) | (0.3) | (4.5) |
| **Gross Investment Cost** | **1.4** | **3.8** | **60.6** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **1.4** | **3.8** | **60.6** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacements - Lennox TS
**Targeted Start Date:** Q2 2016
**Targeted In-Service Date:** Q1 2020
**Targeted Outcome:** *Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Lennox TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission system. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Lennox TS is a critical network station connecting a considerable portion of Ontario Power Generation's ("OPGs") Darlington Nuclear Generating Station to the 500kV and 230kV transmission network. The facility was originally placed in-service in 1974 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with the Northeast Power Coordinating Council ("NPCC") reliability standards is required.

There are 14 ABCBs at Lennox TS that are over 40 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Lennox TS.

This project entails:

- Replacement of eight 230kV ABCBs, six 500kV ABCBs, two 230kV oil circuit breakers, associated breaker disconnect switches, transformer and line disconnect switches as well as protection and control equipment needed to meet NPCC standards; and
- Removal of twenty-two sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

**Alternatives:**
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on detailed cost estimates prepared by Hydro One.

**Outcome:**
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 26.1 | 20.4 | 94.4 |
| Operations, Maintenance & Administration and Removals | 0.0 | (3.5) | (10.7) |
| **Gross Investment Cost** | **26.1** | **16.9** | **83.7** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **26.1** | **16.9** | **83.7** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

# Hydro One Networks – Investment Summary Document

***Sustaining Capital - Stations***

**Investment Name:** Air Blast Circuit Breaker Replacement – Richview TS
**Targeted Start Date:** Q1 2014
**Targeted In-Service Date:** Q4 2018
**Targeted Outcome:** *Operational Effectiveness*

**Need:**
To address Air Blast Circuit Breakers ("ABCBs") and associated auxiliary systems at Richview TS that are in need of replacement due to deteriorated condition, asset demographics, and equipment obsolescence, which directly impacts the operability and reliability of the transmission station. Not proceeding with this investment would result in a significant risk of further equipment deterioration and declining system reliability.

**Investment Summary:**
Richview TS is a critical network station that facilitates bulk power transfers on the 230 kV transmission network and transforms 230kV to 27.6kV for load delivery within the GTA. The facility was originally placed in-service in 1957 and many of the station assets are in need of major work to sustain their functionality. Due to the station's criticality, compliance with NPCC reliability standards is required.

There are twenty-four 230kV ABCBs at Richview TS that are 50 years old. ABCBs are the poorest performing breaker population in Hydro One and have been targeted for replacement. These breakers are more costly to maintain, less reliable then a new standard SF6 breaker, and technical support is no longer available and parts are limited. ABCBs also require high pressure air systems in order to operate. These air systems include compressors, holding tanks, valves and extensive piping and are susceptible to temperature fluctuations that cause air leaks resulting in equipment outages. Replacement of these ABCBs will simultaneously reduce preventive maintenance costs and enable the decommissioning and removal of the high pressure air system at Richview TS.

The project entails:

- Replacement of twenty-four ABCBs, three oil breakers, associated breaker disconnect switches, DC systems as well as protection and control equipment needed to meet NPCC standards; and
- Removal of forty-eight sets of free standing transformers along with the entire high pressure air system which will no longer be required.

Witness: Chong Kiat (CK) Ng

Integration of the replacement of multiple station components into a single project allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

**Alternatives:**
Two alternatives were considered:

- Alternative 1: Continue to maintain the assets (status quo); or
- Alternative 2: Replacement of the assets.

Alternative 2 is the preferred alternative, as Alternative 1 does not address the risk of failure due to asset condition, and would result in increased maintenance expense.

**Basis for Budget Estimate:**
The project cost is based on detailed cost estimate prepared by Hydro One.

**Outcome:**
To eliminate operational risks associated with operating end of life equipment, maintain system reliability, ensure compliance with NPCC requirements, and reduce long term maintenance costs with the conversion of ABCBs to SF6 breakers

**Costs:**

| **($ Millions)** | **2017** | **2018** | **Total** |
|---|---|---|---|
| Capital* and Minor Fixed Assets | 19.5 | 14.3 | 102.3 |
| Operations, Maintenance & Administration and Removals | (2.6) | (0.8) | (6.8) |
| **Gross Investment Cost** | **16.9** | **13.5** | **95.5** |
| Capital Contribution | 0.0 | 0.0 | 0.0 |
| **Net Investment Cost** | **16.9** | **13.5** | **95.5** |

*Includes Overhead at current rates. No Allowance for Funds Used During Construction is charged due to monthly capitalization.

Witness: Chong Kiat (CK) Ng

# SR-01 Air Blast Circuit Breaker Replacement Projects

| | | | |
|---|---|---|---|
| **Start Date:** | Q4 2013 | **Priority:** | High |
| **In-Service Date:** | Q4 2027 | **3 Year Test Period Cost ($M):** | 366.2 |
| **Triggers:** Strategic, System Renewal, Customer Engagement | | | |
| **Outcome:** Increase reliability and performance to large customers and generators; improve reliability to the BES, stage approach to minimize customer outages, reduce maintenance cost associated with End of Life (“EOL”) equipment and air systems, reduce constrained power flow through the station; replace EOL PCT equipment; reduce costs of unplanned outages due to ABCB failures and leaking air systems. | | | |

## A. OVERVIEW

Air Blast Circuit Breaker Replacement Project (the “Project”) involves the replacement of Air Blast Circuit Breakers (“ABCBs”) and their auxiliary station equipment that are at a high risk of failure due to deteriorated condition and asset obsolescence. The principal drivers of the Project are unacceptable reliability performance, high operation and maintenance costs and unavailability of spare parts and technical support due to obsolescence. The majority of installed ABCBs have surpassed their EOL and the entire population of ABCBs will exceed their expected service life by the end 2023 if proactive replacements are not undertaken. Currently, the obsolescence of ABCBs, which were originally installed in the 1970s, already pose significant challenges in terms of the high operating costs required to maintain system reliability. The lack of available spare parts due to the obsolescence of the technology further constrains Hydro One’s ability to maintain these assets and implicitly the resulting system reliability at the appropriate level. Almost half of Hydro One’s ABCBs population is installed at critical stations that are delivery points to hydraulic, gas and nuclear plant operators and interties. Any forced outages at the critical stations due to ABCB failures would adversely impact these sensitive customers, who have expressed the view that a high level of reliability is paramount to their operations. To address customer concerns, high risk to reliability performance of deteriorated ABCB assets, and associated escalating maintenance costs, Hydro One evaluated several alternatives, as described below, and concluded that the have incurred costs prior to the 2020 test year. Likewise, the costs noted in "Forecast 2025+" are project costs forecast beyond 2024.

**Table 2 - Total Investment Cost**

| ($ Millions) | Prev. Years | 2020 | 2021 | 2022 | 2023 | 2024 | Forecast 2025+ | Total |
|---|---|---|---|---|---|---|---|---|
| Capital[1] and Minor Fixed Assets | 464.9 | 112.0 | 133.6 | 138.8 | 133.7 | 101.8 | 104.9 | 1,189.5 |
| Less Removals | 31.6 | 4.5 | 5.2 | 5.3 | 4.5 | 3.1 | 3.3 | 57.5 |
| **Gross Investment Cost** | **433.3** | **107.5** | **128.4** | **133.5** | **129.2** | **98.7** | **101.5** | **1,132.1** |
| Less Capital Contributions | 1.0 | 1.6 | 1.5 | 0.1 | 0.0 | 0.0 | 0.5 | 4.6 |
| **Net Investment Cost** | **432.3** | **105.9** | **126.9** | **133.4** | **129.2** | **98.7** | **101.0** | **1,127.4** |

[1] *Includes overhead at current rates.*

Table 3 below presents the projected costs on an individual project basis. It also provides the total cost, which includes costs incurred in previous years and forecasted beyond 2024, where applicable, for each individual project along with the proposed in-service date.

**Table 3 - Detailed Total Project Costs**

| Project | Net Investment Costs ($ Millions) | | | | | 20-24 Total ($M) | Project Total ($M) | In Service Date |
|---|---|---|---|---|---|---|---|---|
| | 2020 | 2021 | 2022 | 2023 | 2024 | | | |
| Richview TS | 2.5 | 0.0 | 0.0 | 0.0 | 0.0 | 2.5 | 94.9 | 2020 |
| Bruce A TS 230kV | 6.3 | 0.1 | 0.0 | 0.0 | 0.0 | 6.5 | 111.2 | 2020 |
| Beck #2 TS 230kV | 12.4 | 11.6 | 8.9 | 0.3 | 0.0 | 33.1 | 110.2 | 2022 |
| Middleport TS | 27.3 | 22.6 | 11.2 | 12.9 | 1.9 | 76.0 | 104.6 | 2023 |
| Nanticoke TS | 13.4 | 17.1 | 14.8 | 9.3 | 0.9 | 55.6 | 59.4 | 2023 |
| Cherrywood TS 230kV | 17.2 | 13.4 | 13.8 | 4.2 | 0.0 | 48.6 | 88.9 | 2023 |
| Lennox TS | 5.9 | 4.6 | 5.8 | 2.0 | 0.0 | 18.3 | 88.1 | 2023 |
| Bruce B SS 500kV | 12.9 | 16.6 | 20.1 | 18.4 | 10.5 | 78.5 | 85.5 | 2024 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Bruce A TS 500kV | 3.7 | 21.0 | 21.9 | 38.0 | 38.6 | 123.2 | 147.3 | 2025 |
| Essa TS | 0.5 | 6.6 | 20.3 | 13.9 | 14.2 | 55.5 | 71.4 | 2025 |
| Beck #1 SS 115kV | 3.3 | 2.9 | 3.5 | 3.5 | 3.0 | 16.2 | 30.7 | 2026 |
| Cherrywood TS 230kV/500kV | 0.4 | 10.4 | 13.2 | 26.6 | 29.5 | 80.1 | 135.2 | 2027 |
| **Net Investment Cost** | **105.9** | **126.9** | **133.4** | **129.2** | **98.7** | **594.0** | **1127.4** | |

The factors influencing the cost of the Project include:

- The circuit breaker voltage level and the number of ABCB replacements – the higher the voltage levels the higher the cost of equipment needed. Higher voltage levels require additional space requirements due to increased electrical clearances, more structures and etc.
- The station design and configuration - foundation/structural replacements, in-situ or Greenfield replacement. Safety by design based on latest Hydro One standards (i.e. new clearance requirements, Arc Flash requirements and etc.)
- NERC and/or NPCC requirements require physical separation and redundancy
- Outage availability, and reduced contingency concerns customers. Outage availability is more difficult to achieve at nuclear facilities due to stricter contingency planning (N-2 contingency).
- By-pass construction where needed to minimize customer impacts. In many situations, to avoid constraining generation and power flow, additional by passes are required; these are costly to install and are typically removed at the end of the project (i.e. between $3 million and $5 million)

## D. ALTERNATIVES

Hydro One considered the following alternatives before selecting the preferred undertaking.

**Alternative 1: Reactive Component Replacement** is a “Do Nothing” alternative and is based on reactive response as the failures occur, and replacing ABCB sub-components as

**Table 1 - Productivity Savings Forecast Summary ($Millions)**

| $mm | 2020 | 2021 | 2022 | 2023 | 2024 | Total |
|---|---|---|---|---|---|---|
| Operations | 47 | 52 | 53 | 53 | 54 | 259 |
| Progressive Operations (Defined Capital) | 6 | 12 | 12 | 10 | 10 | 49 |
| Corporate | 12 | 11 | 9 | 7 | 6 | 45 |
| **Capital Total** | **$65** | **$74** | **$73** | **$70** | **$70** | **$353** |
| Operations | 9 | 10 | 9 | 9 | 9 | 45 |
| Information Technology | 6 | 9 | 10 | 10 | 10 | 44 |
| Corporate | 7 | 6 | 5 | 4 | 3 | 25 |
| **OM&A Total** | **$22** | **$25** | **$23** | **$23** | **$22** | **$114** |
| Total Defined | **$87** | **$99** | **$97** | **$93** | **$92** | **$468** |
| Progressive Operations (Undefined Capital) | 11 | 27 | 49 | 68 | 81 | 237 |
| **Grand Total** | **$98** | **$126** | **$146** | **$161** | **$173** | **$704** |
| **Progressive Productivity** | | | | | | |
| Progressive Operations (Defined Capital) | 6 | 12 | 12 | 10 | 10 | 49 |
| Progressive Operations (Undefined Capital) | 11 | 27 | 49 | 68 | 81 | 237 |
| Progressive Productivity Placeholder | 17 | 39 | 61 | 78 | 91 | 286 |

As noted in the table above, Hydro One has identified savings opportunities totalling approximately $704M over the 2020-2024 TSP period. This reflects Tier 1 Productivity savings only. There are $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings. This latter category of savings falls within “Progressive Productivity”. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB’s decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned

Witness: Joel Jodoin, Andrew Spencer

# UNDERTAKING - JT 2.28

**Reference:**
SEC-026

**Undertaking:**
Regarding SEC 26, to consider if further level of details can be provided beyond what is currently provided in evidence regarding the base number for each one of the initiatives.

**Response:**
Please see Attachment 1 to this Exhibit.

Witness: Joel Jodoin

| | | | | Updated Savings | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Category | Initiative Grouping | Measurement and Expected Benefit | 2016A | 2017A | 2018A | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Baseline |
| Capital | Operations | Engineering | Cost Reduction from Software Implementation<br>*Estimated by quantifying the expected FTE reductions in Engineering through the implementation of EDM software enhancements* | $ - | $ - | $ - | $ 0.4 | $ 0.9 | $ 1.1 | $ 1.4 | $ 1.4 | $ 1.4 | 129 Tx FTEs (2017 actual) in records and drafting job functions. |
| | | Fleet Telematics and Right-Sizing | Fleet Rationalization - Unit Based Capital Plan Reduction<br>*Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan* | $ - | $ 1.9 | $ 10.2 | $ 10.6 | $ 11.0 | $ 11.1 | $ 11.4 | $ 11.6 | $ 11.3 | Baseline is $59.7M annual spend (HONI Total). See EB-2017-0049 Exhibit J 2.3 for detailed methodology |
| | | Transmission and Stations | Cost Reduction based on Historical spend<br>*Expected Capital allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence* | $ - | $ 1.8 | $ 0.6 | $ 0.7 | $ 0.7 | $ 0.7 | $ 0.7 | $ 0.7 | $ 0.7 | Savings Calculated per occurance for TWHQ (varies by zone - approx. $185). Baseline for Transmission and Stations efficiencies (BGIS Outsourcing )is 650k. |
| | | OT Reductions | Overtime Reductions<br>*Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline* | $ - | $ 1.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | Savings calculated against 2015 baseline of 12.3% OT as a % of Base Hours - please refer to I-07-SEC-25 |
| | | Procurement | Lower Cost per Unit - Historical Baseline vs Actual<br>*Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Capital program spend)* | $ 1.2 | $ 12.8 | $ 27.9 | $ 25.1 | $ 30.3 | $ 34.9 | $ 35.8 | $ 35.7 | $ 37.1 | Calculation described in EB-2017-0049 Exhibit J 2.3. As there are tens of thousands of materials being tracked (automated system reports) Hydro One is unable to reasonably provide the baseline price for each item. |
| | | Progressive Defined | Targeted Efficiencies - Defined<br>*Efficiencies that have been allocated to specific Operating initiatives that are not yet proven. Allocations taken in Business Plan based on preliminary estimates. Ex - Hydro Vac reduction, Temp Access Roads* | $ - | $ - | $ - | $ 5.0 | $ 6.1 | $ 11.6 | $ 11.6 | $ 10.1 | $ 10.1 | Refer to JT 1.09 for an Update on Progressive initiatives. |
| | | Progressive Undefined | Targeted Efficiencies - Undefined<br>*Escalating commitment of 1-3% of capital work program to be allocated to future initiatives as they are defined. Included as a Top Line capital reduction* | $ - | $ - | $ - | $ - | $ 10.9 | $ 27.4 | $ 49.4 | $ 67.9 | $ 80.9 | N/A |
| | | Scheduling Tool | Cost Reduction from Software Implementation<br>*Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements* | $ - | $ - | $ 0.2 | $ 0.9 | $ 0.9 | $ 0.9 | $ 0.9 | $ 0.9 | $ 0.9 | 32 Tx FTEs (2017 Actual) in Scheduling job functions |
| | | Wrench Time | Lower Cost Per Unit of Operation<br>*Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.* | $ - | $ - | $ - | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | Labour efficiency per Task:<br>2015 Labour Hours Less Estimated Labour Hours for planned orders multiplied by $143 per hour. Due to the volume of orders Hydro One is unable to reasonably provide the baseline price for each Task. |
| OM&A | Information Technology | Contract Reductions | Cost Reduction Based on Historical Spend<br>*Lower cost resulting from Inergi IT Contract renegotiation. Measured against baseline spend for same scope of work* | $ 2.0 | $ 2.3 | $ 6.6 | $ 6.3 | $ 6.4 | $ 8.9 | $ 9.6 | $ 9.6 | $ 9.6 | Baseline is $65.5M (Total 2015 Actual/2016 Plan) |
| | Operations | Engineering | Cost Reduction from Software Implementation<br>*Estimated by quantifying the expected FTE and contractor reductions in Engineering through the implementation of PCMIS software enhancements* | $ - | $ - | $ 0.7 | $ 0.6 | $ 0.6 | $ 0.6 | $ 0.6 | $ 0.6 | $ 0.6 | Baseline is 13 Non-Regular FTEs (2017 Historical Actual) in P&C functions. |
| | | Fleet Telematics and Right-Sizing | Fleet Rationalization - Unit Based Capital Plan Reduction<br>*Estimated by utilizing Telematics data on fleet utilization and then measures the expected unit based reduction in the capital plan* | $ - | $ 0.5 | $ 0.2 | $ - | $ - | $ - | $ - | $ - | $ - | There are no savings included in the plan years. |
| | | Forestry Initiatives | Lower Cost per KM<br>*Estimated based on reductions in cost due to staff policy for inclement weather and expected overall unit volume reduction in trouble calls* | $ - | $ - | $ 1.3 | $ 2.1 | $ 2.0 | $ 3.4 | $ 2.0 | $ 2.4 | $ 1.9 | Estimate per occurance for inclement weather @ $85 per hour. Forestry baseline is $1566 per km (2015, escalated for labour inflation) |
| | | Transmission and Stations | Cost Reduction based on Historical spend<br>*Expected OM&A allocation based on historical spend for Transmission and Stations efficiencies and Temporary work HQ. Calculated by measuring expected benefit per occurrence* | $ - | $ 0.8 | $ 1.8 | $ 1.2 | $ 1.2 | $ 1.2 | $ 1.2 | $ 1.2 | $ 1.2 | Savings Calculated per occurance for TWHQ. See above in this table. |
| | | Network Operating Efficiencies | Operational Program Efficiencies<br>*Unit cost reduction in completing Load Transfer studies through Network Operating group* | $ - | $ - | $ 0.4 | $ 1.0 | $ 1.0 | $ 1.0 | $ 1.0 | $ 1.0 | $ 1.0 | Baseline is historical program budget of $1.0M |
| | | OT Reductions | Overtime Reductions<br>*Targeted effort to reduce the number of relative OT hours worked as a % vs prior year baseline* | $ - | $ 1.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | $ 0.5 | See OT reductions within the Capital section above in this table |

| | Category | Initiative Grouping | Measurement and Expected Benefit | Updated Savings 2016A | 2017A | 2018A | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Baseline |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Procurement | Lower Cost per Unit - Historical Baseline vs Actual<br>*Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions* | $ 1.8 | $ 2.9 | $ 1.7 | $ 0.9 | $ 0.8 | $ 0.8 | $ 0.9 | $ 0.8 | $ 0.8 | See Procurement category within the Capital section above in this table |
| | | Scheduling Tool | Cost Reduction from Software Implementation<br>*Estimated by quantifying the expected FTE reductions in Scheduling Staff through the implementation of software enhancements* | $ - | $ - | $ 0.2 | $ - | $ - | $ - | $ - | $ - | $ - | See Scheduling Tool category within the Capital section above in this table |
| | | Wrench Time | Lower Cost Per Unit of Operation<br>*Utilize unit reporting to compare like for like work in actuals vs baseline year to determine $ savings per operation.* | $ - | $ - | $ 1.5 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | See Wrench Time category within the Capital section above in this table |
| CCC | Corporate | Corporate Initiatives | Corporate Cost Initiative<br>*Identified reductions in vacancies and contractor and consulting spending* | $ 2.3 | $ 1.2 | $ 1.4 | $ 20.1 | $ 19.1 | $ 16.5 | $ 13.6 | $ 11.3 | $ 9.4 | Baseline is $303.9M (2019 Prior Plan (2018-2023). Tx is allocated by B&V methodology. |
| | Operations | Procurement | Lower Cost per Unit - Historical Baseline vs Actual<br>*Savings are estimated at a category level based on historical spend, expected and achieved negotiated savings, and updated per business plan assumptions (Corporate Allocation)* | $ 0.1 | $ 1.8 | $ 5.4 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | $ 2.3 | Baseline is $0. Savings are quantified as a Early Pay credit (negotiated cost reduction) received from Vendors. |
| | | | **Total Capital** | **$ 1.2** | **$ 18.0** | **$ 39.4** | **$ 43.6** | **$ 61.7** | **$ 88.7** | **$ 112.2** | **$ 129.2** | **$ 143.4** | |
| | | | **Total OM&A** | **$ 3.8** | **$ 8.0** | **$ 14.8** | **$ 14.7** | **$ 14.7** | **$ 18.6** | **$ 17.9** | **$ 18.3** | **$ 17.8** | |
| | | | **Total Common** | **$ 2.3** | **$ 3.1** | **$ 6.8** | **$ 22.4** | **$ 21.5** | **$ 18.8** | **$ 16.0** | **$ 13.6** | **$ 11.7** | |
| | | | | **$ 7.3** | **$ 29.1** | **$ 61.0** | **$ 80.8** | **$ 97.9** | **$ 126.1** | **$ 146.1** | **$ 161.1** | **$ 172.9** | |

| Performance Outcomes | Performance Categories | Measures | 2014 | 2015 | 2016 | 2017 | 2018 | Targets 2019 | Targets 2020 | Targets 2021 | Targets 2022 | Targets 2023 | Targets 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Focus | Customer Satisfaction | Satisfaction with Outage Planning Procedures (% Satisfied) | 86 | 92 | 89 | 94 | 85 | 86 | 86 | 87 | 87 | 88 | 88 |
| | | Overall Customer Satisfaction (% Satisfied) | 77 | 85 | 78 | 88 | 90 | 88 | 88 | 88 | 88 | 88 | 88 |
| | Service Quality | Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs | 11.8 | 14.3 | 9.7 | 9.5 | 10.1 | 12.0 | 11.7 | 11.5 | 11.3 | 11.0 | 10.8 |
| Operational Effectiveness | Safety | Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked) | 1.8 | 1.7 | 1.1 | 1.2 | 1.1 | 1.1 | 1.1 | 1.0 | 0.9 | 0.9 | 0.9 |
| | System Reliability | T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point) | 0.60 | 0.59 | 0.46 | 0.65 | 0.83 | 0.55 | 0.54 | 0.53 | 0.52 | 0.51 | 0.50 |
| | | T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point) | 0.48 | 0.50 | 0.33 | 0.47 | 0.50 | 0.49 | 0.48 | 0.48 | 0.47 | 0.46 | 0.45 |
| | | T-SAIDI (Ave minutes of interruptions per Deliver Point) | 36.7 | 43.9 | 80.8 | 42.8 | 70.0 | 35.4 | 34.66 | 33.96 | 33.28 | 32.62 | 31.97 |
| | | System Unavailability (%) | 0.48 | 0.63 | 0.70 | 0.69 | 0.71 | 0.48 | 0.47 | 0.47 | 0.46 | 0.45 | 0.44 |
| | | Unsupplied energy (minutes) | 12.2 | 11.8 | 11.4 | 13.2 | 19.5 | 9.8 | 9.59 | 9.40 | 9.21 | 9.02 | 8.84 |
| | Asset & Project Management | Transmission System Plan Implementation Progress (%) | 99 | 105 | 100 | 94 | 99 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | CapEx as % of Budget | 90 | 106 | 105 | 100 | 98 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | OM&A Program Accomplishment (composite index) | | 97 | 99 | 108 | 108 | 100 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| | | Capital Program Accomplishment (composite index) | | 122 | 59 | 88 | 116 | 100 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| | Cost Control | Total OM&A and Capital per Gross Fixed Asset Value (%) | 8.4 | 9.0 | 8.6 | 7.9 | 7.7 | 7.3 | 7.8 | 7.9 | 7.7 | 7.3 | 7.0 |
| | | OM&A per Gross Fixed Asset Value (%) | 2.7 | 2.9 | 2.5 | 2.3 | 2.3 | 1.8 | 1.8 | 1.7 | 1.6 | 1.5 | 1.5 |
| | | Line Clearing Cost per kilometer ($/km) | 2,495 | 2,234 | 1,966 | 2,100 | 2,797 | 2,295 | 2,264 | 2,200 | 2,175 | 2,100 | 2,100 |
| | | Brush Control Cost per Hectare ($/Ha) | 1,624 | 1,566 | 1,542 | 1,356 | 1,539 | 1,625 | 1,620 | 1,630 | 1,608 | 1,608 | 1,608 |
| Public Policy Responsiveness | Connection of Renewable Generation | % on-time completion of renewables customer impact assessments | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing | Regional Infrastructure Planning progress - Deliverables met, % | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | End-of-Life Right-Sizing Assessment Expectation | | | | Met | Met | Met | Met | Met | Met | Met | Met |
| Financial Performance | Financial Ratios | Liquidity: Current Ratio (Current Assets/Current Liabilities) | 0.69 | 0.13 | 0.20 | 0.13 | 0.12 | | | | | | |
| | | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | 1.16 | 1.39 | 1.43 | 1.47 | 1.53 | | | | | | |
| | | Profitability: Regulatory Return on Equity — Deemed (included in rates) | 9.36 | 9.30 | 9.19 | 8.78 | 9.00 | | | | | | |
| | | Profitability: Regulatory Return on Equity — Achieved | 13.12 | 10.93 | 10.02 | 9.03 | 11.08 | | | | | | |

**Figure 1 – Evolved Electricity Transmitter Scorecard & Targets – Hydro One Networks Inc.**[4]

[4] Satisfaction with Outage Planning Procedures survey was not performed in 2013.The return on equity achieved values for 2013 to 2015 were restated.

Witness: Bruno Jesus

**Overview of Hydro One's Transmission Performance Measures**

*Customer Focus*

The measures in Table 1 were selected to demonstrate that services are provided to meet customers' expected level of service and align with the OEB's Decision.

**Table 1 - Customer Focus Measures**

| Performance Category | Measures | Description |
|---|---|---|
| **Service Quality** | Satisfaction with Outage Planning Procedures (% Satisfied) | The Ontario Grid Control Centre ("OGCC") Customer satisfaction survey relates Customer Satisfaction with relevant business processes and transactional customer experience. The question asked is: How would you rate Hydro One's OGCC procedures on outage planning? |
| | Customer Delivery Point Performance, Standard outliers as % of Total Delivery Points | The percentage of customer Delivery Points ("DPs") deemed as either group or individual outliers. |
| **Customer Satisfaction** | Overall Customer Satisfaction, corporate survey (% Satisfied) | This measure reflects the overall satisfaction levels of three major transmission customer segments (Transmission End Users, Local Distribution Companies ("LDC") and Transmission-Connected Customer Generators). The survey measures customers' overall opinion of Hydro One (whether they have interacted with Hydro One recently or not). Hydro One seeks to uncover perceptions of how well it is meeting customer expectations and delivering on critical success factors. The survey is conducted online followed by computer-assisted telephone interviewing if customer prefers/is not reached. |

*Operational Effectiveness*

The measures in Table 2 were selected to demonstrate Hydro One's commitment to continuous improvement in performance and execution. The measures also show how Hydro One delivers on system reliability and service quality objectives.

**Table 2 - Operational Effectiveness Measures**[5]

| Performance Category | Measure | Description |
|---|---|---|
| **Safety** | Recordable Rate (#Recordable Injuries/Illnesses per 200,000 hours worked) | Work-related injuries/illnesses to that result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other health care professional and are confirmed by a Hydro One Occupational Health Nurse. The measure applies to Hydro One Networks Inc. employees only (not contractors). |
| **System Reliability** | T-SAIFI-S (Sustained Interruption Frequency) (Average # of times that power to a Customer is interrupted per Delivery Point) | Average Frequency of Delivery Point Sustained Interruptions is an indicator of the average number of unplanned interruptions that customers experience and is presented as number of interruptions per delivery point per year. Only includes sustained (1 minute and longer) interruptions. |
| | T-SAIFI-M (Momentary Interruption Frequency) (Average # of times that power to a Customer is interrupted per Delivery Point) | Average Frequency of Delivery Point Momentary Interruptions is an indicator of the average number of unplanned interruptions that customers experienced and is presented as number of interruptions per delivery point per year. Only includes momentary (less than 1 minute) interruptions. |
| | T-SAIDI (Duration) (Average # minutes that power to a Customer is interrupted per Delivery Point) | Average Duration of Delivery Point Interruptions is an indicator of the average minutes of unplanned interruptions that customers experienced and presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association ("CEA") industry standard) interruptions contribute to this measure. |

[5] For OEB reporting and filing, capital expenditures have been remapped to the OEB categories of System Access, System Renewal, System Service, and General Plant. Internally, Hydro One uses Sustainment, Development, Operations, and Common Corporate Costs & Other Costs ("SDOC") as categories for both OM&A and capital. For internal processes, including the supporting data as well as generating and reporting on scorecards, Hydro One utilizes the SDOC categories. To maintain alignment with the existing internal processes and to provide continuity with the previous application (EB-2016-0160), the metrics have not been renamed to the OEB categories.

| Performance Category | Measure | Description |
|---|---|---|
| | System Unavailability (% of time system equipment is unavailable) | Transmission System Unavailability captures the total duration transmission equipment is out of service due to unplanned outages. |
| | Unsupplied Energy (minutes) | Unsupplied Energy is an indicator of total energy not supplied to customers due to delivery point unplanned interruptions. In order to make it comparable among different sizes of utilities, the unsupplied energy is normalized by the system peak. The unit of the measure of normalized unsupplied energy is expressed in "system minutes". |
| **Asset & Project Management** | Transmission System Plan Implementation Progress | The Transmission System Plan Implementation Progress measure compares the total actual in-year sustainment, development, and operating expenditures for in-service additions to the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance. |
| | Capital Expenditures as % of Budget | Progress is measured as the ratio of actual total capital expenditures to the total amount of planned capital expenditures. |
| | Operations, Maintenance, & Administration ("OM&A") Program Accomplishment (composite index) | The Transmission ("Tx") OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) Forestry Line Clearing; 2) Brush Control; 3) PCB Testing and Retro fill; and Station Preventive Maintenance programs which include 4) Power Equipment, 5) Ancillary Equipment, 6) Protection and Control, 7) Telecom, 8)Infrastructure. |
| | Capital Program Accomplishment (composite index) | The Tx Capital Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx Capital Programs against the weighted budget. The six programs monitored for this measure include the Steel Structure Coating Program, Tx Lines Insulator Replacement Program, Tx Wood Pole Replacement, Tower Foundation Refurbishment, Shieldwire Replacement and Purchase of Station Spare Transformers. |
| **Cost Control** | Total OM&A and Capital per Gross Book Value of In-Service Assets | Demonstrates Transmission cost effectiveness by comparing the ratio of Total Capital and OM&A to Gross Book Value of Fixed Asset costs. |

| Performance Category | Measure | Description |
|---|---|---|
| | OM&A/Gross Fixed Asset Value (%) | Demonstrates Transmission cost effectiveness by comparing the ratio of OM&A to Gross Book Value of Fixed Asset costs. |
| | Line Clearing Cost per kilometer ($/km) | Cost associated with line clearing activities, per kilometer completed for the year. |
| | Brush Control Cost per Hectare ($/Ha) | Cost associated with brush control, per hectare completed for the year. |

*Public Policy Responsiveness*

The measures in Table 3 were selected to demonstrate Hydro One's commitment to deliver on the obligations mandated by the government and regulatory agencies.

**Table 3 - Public Policy Responsiveness Measures**

| Performance Category | Measure | Description |
|---|---|---|
| **Renewable Energy** | % on-time completion of renewables customer impact assessments | For Transmission-connected generators, Hydro One is obligated under the Transmission System Code to complete a customer impact assessment (CIA) for renewables in 150 days. |
| **Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right Sizing** | Regional Infrastructure Planning Progress: % Deliverables Met | Measures progress in meeting the deliverables including meeting the Transmission System Code prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and LDC status update letters. |
| | End-of-Life Right-Sizing Assessment Expectation | This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing end-of-life equipment are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. |

*Financial Performance*

The measures in Table 4 were selected to provide financial visibility and to demonstrate that the continuous improvements in execution and cost performance highlighted in 'Operational Effectiveness' are sustainable. The measures used for the Electricity

Transmission Scorecard align with the Financial Ratio measures used in the Electricity Distributor Scorecard.

**Table 4 - Financial Performance Measures**

| Performance Category | Measures | Description |
|---|---|---|
| **Financial Ratios** | Liquidity: Current Ratio (Current Assets/Current Liabilities) | Hydro One measures the ratio of current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and that can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as short term debts or financial obligations that become due within the year. |
| | Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio | The debt-to-equity ratio is a measure of Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5). |
| | Profitability: Regulatory Return on Equity -Deemed Return on Equity (included in rates) | Measures the OEB-approved Return on Equity that is embedded in the transmitter's base rates. Return on Equity is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB. |
| | Profitability: Regulatory Return on Equity -Achieved Regulated Return on Equity | Measures the transmitter's achieved Regulated Return on Equity earned in the preceding fiscal year. The reported return is calculated on the same basis that was used in establishing the transmitter's base rates. This shows the utility's actual Return on Equity earned each year. |

**Response to OEB Directions from EB-2016-0160**

*Customer Satisfaction*

In the Decision, the OEB directed Hydro One to develop performance indicators that better reflect the satisfaction level of the ultimate end-use customer. The OEB also indicated that it does not consider the satisfaction level of a directly connected LDC to be indicative of the LDC customers' level of satisfaction, and that LDCs do not necessarily represent the interests of their customers on transmission issues nor do they suffer the same negative consequences if transmission performance levels are poor.

# UNDERTAKING - JT 1.16

**Reference:**
I-12-AMPCO-023

**Undertaking:**
To provide the refined cost and schedule metrics that Hydro One uses to track cost schedule and scope, as referred to in AMPCO 23.

**Response:**
Hydro One is continuously improving the reports it uses to evaluate project performance. Below is a list of metrics used on both a project and portfolio basis.

**Project Level Metrics:**
- On-time: Project In-Service Date Forecast versus Current Approved
- On-time: Project In-Service Date Forecast versus Original Approved
- On-budget: Gross Project Total Forecast versus Current Approved
- On-budget: Gross Project Total Forecast versus Original Approved

**Portfolio Level Metrics:**
- In-Service Additions: Annual Forecast versus Budget
- Capital Expenditures: Annual Forecast versus Budget
- Portfolio Risk: Number of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Portfolio Risk: Value of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Project Cost Performance: Number of Projects complete within AACE Estimate Class Range documented in original approval
- Project Cost Performance: Value of Projects complete within AACE Estimate Class Range documented in original approval
- Cost Variance Distribution: Portion of Project Portfolio Delivered On Budget, Over Budget, Under Budget
- Cost Variance Distribution: Standard Deviation of Project Cost Performance represented as a percentage of original Budgets
- Schedule Variance Distribution: Portion of Project Portfolio Delivered On-time, Late, Early
- Schedule Variance Distribution: Standard Deviation of Schedule Variance in Days

Witness: Andrew Spencer

# 2019 Team Scorecard

| Corporate Goal | Component Weight | Definition | Measure | Sub-Component Weight | 2019 Performance Levels | | |
|---|---|---|---|---|---|---|---|
| | | | | | Threshold | Target | Maximum |
| **Health & Safety** * | 10% | Recordable Incidents | Incidents per 200,000 hours | 100% | 1.11 | 1.05 | 0.99 |
| **Work Program** | 25% | Transmissions (Tx) Reliability – Average duration of unplanned interruptions to multi-circuit (mc) supplied delivery points (SAIDI) | System Average Interruption Duration Index - mc (minutes) | 25% | 8.4 | 8.1 | 6.3 |
| | | Distribution (Dx) Reliability – Average duration of interruptions in hours that a customer can expect to experience (SAIDI) | System Average Interruption Duration Index (hours) | 25% | 7.0 | 6.3 | 6.0 |
| | | Tx In-Service Additions - Delivery Accuracy, ability to deliver to a budget | Variance (%) to approved budget of $951M | 25% | +/- 6% | +/- 4% | +/-1% |
| | | Dx In-Service Additions - Delivery Accuracy, ability to deliver to a budget | Variance (%) to approved budget of $556.5M | 25% | - 5 % / + 4% | - 3% / + 2% | - 1% / + 1% |
| **Net Income** | 30% | Net Income to Common Shareholders | $M | 100% | Redacted | | |
| **Productivity** | 10% | Savings in $M | $M | 100% | $164.1 | $193 | $222 |
| **Customer** | 25% | Residential & Small Business | Customer Satisfaction | 40% | 71% | 77% | 80% |
| | | Transmission Connected & Local Distribution Companies (LDCs) | Customer Satisfaction | 40% | 85% | 90% | 92% |
| | | Commercial and Industrial | Customer Satisfaction | 20% | 73% | 77% | 80% |

* *If the company has a fatality, the attained Safety measure will be reduced to 0% based on the findings of the System Investigation*

look at these projects first for reprioritization. Failure to complete Low Priority projects is not expected to have significant detrimental effects on the system in the near term.

**Table 5 - System Access - Material Capital Investments Proposed**

| ISD | Investment Name | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| SA-01 | Connect New IAMGOLD Mine | 24.9 | 0.0 | 0.0 | 0.0 | 0.0 |
| SA-02 | Horner TS: Build a Second 230/27.6kV Station | 29.9 | 0.0 | 0.0 | 0.0 | 0.0 |
| SA-03 | Halton TS: Build a Second 230/27.6kV Station | 8.0 | 17.7 | 6.0 | 0.0 | 0.0 |
| SA-04 | Connect Metrolinx Traction Substations | 6.5 | 7.9 | 7.1 | 1.0 | 0.0 |
| SA-05 | Future Transmission Load Connection Plans | 0.0 | 5.0 | 24.9 | 24.9 | 0.0 |
| SA-06 | Protection and Control Modifications for Distributed Generation | 3.8 | 3.1 | 2.7 | 2.8 | 2.8 |
| SA-07 | Secondary Land Use Transmission Asset Modifications | 55.1 | 15.0 | 13.9 | 15.6 | 3.9 |
| | **System Access Projects & Programs Less Than $3M** | **27.6** | **9.4** | **8.5** | **7.8** | **9.2** |
| **Total Gross System Access Capital ($M)** | | **155.7** | **58.1** | **63.0** | **52.0** | **15.8** |
| | *Less Capital Contributions ($M)* | *(130.9)* | *(46.7)* | *(51.3)* | *(39.3)* | *(11.7)* |
| **Total Net System Access Capital ($M)** | | **24.8** | **11.3** | **11.7** | **12.7** | **4.1** |

**Table 6 - System Renewal - Material Capital Investments Proposed**

| ISD | Investment Name | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| SR-01 | Air Blast Circuit Breaker Replacement Projects | 107.5 | 128.4 | 133.5 | 129.2 | 98.7 |
| SR-02 | Station Reinvestment Projects | 107.0 | 125.4 | 120.6 | 87.9 | 53.9 |
| SR-03 | Bulk Station Transformer Replacement Projects | 33.2 | 51.8 | 72.5 | 131.5 | 113.8 |
| SR-04 | Bulk Station Switchgear and Ancillary Equipment Replacement Projects | 17.5 | 32.4 | 41.4 | 34.6 | 49.3 |
| SR-05 | Load Station Transformer Replacement Projects | 91.2 | 132.3 | 129.4 | 178.5 | 200.0 |
| SR-06 | Load Station Switchgear and Ancillary Equipment Replacement Projects | 19.2 | 30.8 | 47.5 | 58.4 | 77.0 |
| SR-07 | Protection and Automation Replacement Projects | 6.7 | 8.6 | 12.7 | 12.2 | 21.7 |
| SR-08 | John Transformer Station Reinvestment Project | 3.5 | 17.9 | 25.6 | 24.0 | 20.9 |

| | | | | | | |
|---|---|---|---|---|---|---|
| SR-09 | Transmission Station Demand and Spares and Targeted Assets | 44.2 | 36.4 | 37.0 | 37.7 | 38.3 |
| SR-10 | Transformer Protection Replacement | 3.8 | 0.0 | 0.0 | 0.0 | 0.0 |
| SR-11 | Legacy SONET System Replacement | 4.1 | 26.0 | 27.6 | 28.1 | 28.1 |
| SR-12 | Telecom Performance Improvements | 0.0 | 0.9 | 5.5 | 3.7 | 0.0 |
| SR-13 | ADSS Fibre Optic Cable Replacements | 7.0 | 7.1 | 1.0 | 0.0 | 0.0 |
| SR-14 | Mobile Radio System Replacement | 2.9 | 6.2 | 6.1 | 4.0 | 0.0 |
| SR-15 | Telecom Fibre IRU Agreement Renewals | 0.0 | 2.8 | 8.5 | 2.6 | 1.5 |
| SR-16 | NERC CIP-014 Physical Security Implementation | 18.0 | 18.0 | 18.0 | 0.0 | 0.0 |
| SR-17 | NERC CIP Transient Cyber Asset Project | 3.5 | 0.0 | 0.0 | 0.0 | 0.0 |
| SR-18 | PSIT Cyber Equipment Replacement | 1.0 | 5.0 | 7.7 | 7.0 | 3.4 |
| SR-19 | Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures | 81.8 | 122.1 | 94.5 | 51.0 | 75.9 |
| SR-20 | Transmission Line Refurbishment - Near End of Life ACSR Conductor | 62.2 | 63.4 | 111.7 | 117.8 | 137.7 |
| SR-21 | Wood Pole Structure Replacements | 51.0 | 52.0 | 53.0 | 54.1 | 55.2 |
| SR-22 | Steel Structure Coating Program | 11.4 | 21.8 | 22.3 | 22.7 | 23.2 |
| SR-23 | Tower Foundation Assess/Clean/Coat Program | 11.8 | 22.3 | 22.8 | 23.3 | 23.7 |
| SR-24 | Transmission Line Shieldwire Replacement | 12.3 | 12.6 | 12.8 | 13.1 | 13.4 |
| SR-25 | Transmission Line Insulator Replacement | 68.3 | 69.7 | 66.3 | 67.6 | 68.9 |
| SR-26 | Transmission Line Emergency Restoration | 9.6 | 9.8 | 10.0 | 10.2 | 10.4 |
| SR-27 | C5E/C7E Underground Cable Replacement | 2.1 | 29.8 | 30.9 | 32.2 | 29.2 |
| SR-28 | OPGW Infrastructure Projects | 5.3 | 7.5 | 2.2 | 6.2 | 9.7 |
| SR-29 | Physical Security ISL Application Replacement | 5.0 | 1.1 | 0.0 | 0.0 | 0.0 |
| **System Renewal Projects & Programs Less Than $3M** | | **77.8** | **67.3** | **60.1** | **44.1** | **41.1** |
| **Total Gross System Renewal Capital ($M)** | | **869.1** | **1,109.2** | **1,181.1** | **1,181.5** | **1,194.9** |
| *Less Capital Contributions ($M)* | | *(3.8)* | *(6.1)* | *(8.3)* | *(4.1)* | *(1.1)* |
| **Total Net System Renewal Capital ($M)** | | **865.2** | **1,103.1** | **1,172.8** | **1,177.4** | **1,193.8** |

### Table 7 - System Service - Material Capital Investments Proposed

| ISD | Investment Name | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| SS-01 | Lennox TS: Install 500kV Shunt Reactors | 32.3 | 0.0 | 0.0 | 0.0 | 0.0 |
| SS-02 | Wataynikaneyap Line to Pickle Lake Connection | 24.9 | 1.5 | 0.0 | 0.0 | 0.0 |

| ISD | Investment Name | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| SS-03 | Nanticoke TS: Connect HVDC Lake Erie Circuits | 3.0 | 10.0 | 4.0 | 0.0 | 0.0 |
| SS-04 | East-West Tie Connection | 46.3 | 38.8 | 22.6 | 0.0 | 0.0 |
| SS-05 | St. Lawrence TS: Phase Shifter Upgrade | 9.0 | 18.0 | 9.0 | 0.0 | 0.0 |
| SS-06 | Merivale TS to Hawthorne TS: 230kV Conductor Upgrade | 5.0 | 10.0 | 8.4 | 0.0 | 0.0 |
| SS-07 | Milton SS: Station Expansion and Connect 230kV Circuits | 0.0 | 2.0 | 3.0 | 69.4 | 119.1 |
| SS-08 | Northwest Bulk Transmission Line | 8.0 | 12.9 | 8.9 | 0.0 | 0.0 |
| SS-09 | Barrie Area Transmission Upgrade | 38.1 | 28.2 | 8.5 | 0.0 | 0.0 |
| SS-10 | Kapuskasing Area Transmission Reinforcement | 6.7 | 3.8 | 0.0 | 0.0 | 0.0 |
| SS-11 | South Nepean Transmission Reinforcement | 27.5 | 10.5 | 0.0 | 0.0 | 0.0 |
| SS-12 | Alymer-Tillsonburg Area Transmission Reinforcement | 10.0 | 13.1 | 6.1 | 0.0 | 0.0 |
| SS-13 | Leamington Area Transmission Reinforcement | 4.9 | 9.7 | 59.1 | 63.8 | 63.8 |
| SS-14 | Southwest GTA Transmission Reinforcement | 10.3 | 7.8 | 6.9 | 3.9 | 2.0 |
| SS-15 | Future Transmission Regional Plans | 0.0 | 0.0 | 10.5 | 19.6 | 0.0 |
| SS-16 | Customer Power Quality Program | 3.3 | 3.4 | 3.4 | 3.4 | 3.5 |
| **System Service Projects & Programs Less Than $3M** | | **9.1** | **8.2** | **9.9** | **14.0** | **15.9** |
| **Total Gross System Service Capital ($M)** | | **238.3** | **177.9** | **160.3** | **174.3** | **204.2** |
| *Less Capital Contributions ($M)* | | *(34.2)* | *(29.7)* | *(8.5)* | *0.0* | *0.0* |
| **Total Net System Service Capital ($M)** | | **204.1** | **148.2** | **151.8** | **174.3** | **204.2** |

**Table 8 - General Plant - Material Capital Investments Proposed**

| ISD | Investment Name | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| GP-01 | Integrated System Operations Centre - New Facility Development | 32.4 | 12.7 | 0.0 | 0.0 | 0.0 |
| GP-02 | Grid Control Network Sustainment | 8.0 | 6.1 | 6.3 | 6.5 | 6.6 |
| GP-03 | Network Management System Capital Sustainment | 0.0 | 7.8 | 22.4 | 8.2 | 0.0 |
| GP-04 | Integrated Voice Communications and Telephony System Refresh | 0.0 | 1.9 | 3.2 | 1.1 | 0.0 |
| GP-05 | Transmission Non-Operational Data Management System | 5.2 | 5.3 | 5.4 | 5.5 | 1.1 |
| GP-06 | Operating Common IT Infrastructure | 0.8 | 2.0 | 3.7 | 3.3 | 2.2 |
| GP-07 | Hardware/Software Refresh and Maintenance | 2.0 | 2.0 | 1.9 | 1.9 | 5.8 |
| GP-08 | Corporate Services Transformation - HR / Payroll | 5.0 | 1.5 | 0.0 | 0.0 | 0.0 |
| GP-09 | Corporate Services Transformation - Finance | 1.0 | 3.0 | 5.0 | 6.5 | 5.0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| GP-10 | Facility Accommodation & Improvements Service Centres & Admin | 8.1 | 4.9 | 8.2 | 16.4 | 4.3 |
| GP-11 | Transmission Facilities & Site Improvements | 9.4 | 9.5 | 9.6 | 9.7 | 9.9 |
| GP-12 | Transport & Work Equipment | 13.2 | 13.2 | 13.3 | 13.3 | 13.3 |
| **General Plant Projects & Programs Less Than $3M** | | **30.2** | **24.3** | **15.8** | **11.1** | **10.7** |
| **Total Gross System Service Capital ($M)** | | **115.4** | **94.4** | **94.7** | **83.6** | **58.9** |
| **Total Net General Plant Capital ($M)** | | **115.4** | **94.4** | **94.7** | **83.6** | **58.9** |

### 3.3.6.2 (5.4.3.2 D) SUMMARY OF INVESTMENTS REQUIRING LEAVE TO CONSTRUCT

Investments listed in Table 9 below are identified as requiring a leave to construct. Details of the evidence pertaining to the leave to construct are provided within the relevant ISDs.

**Table 9 - List of Investments Requiring Leave to Construct**

| ISD | Investment Name |
|---|---|
| **System Access** | |
| SA-01 | Connect New IAMGOLD Mine |
| **System Service** | |
| SS-04 | East-West Tie Connection |
| SS-06 | Merivale TS to Hawthorne TS: 230kV Conductor Upgrade |
| SS-07 | Milton SS: Station Expansion and Connect 230kV Circuits |
| SS-09 | Barrie TS: Upgrade Station and Reconductor E3B/E4B Circuits |
| SS-10 | Kapuskasing Area Transmission Reinforcement |
| SS-11 | South Nepean Transmission Reinforcement |
| SS-12 | Aylmer-Tillsonburg Area Transmission Reinforcement |
| SS-13 | Leamington Area Transmission Reinforcement |
| SS-14 | Southwest GTA Transmission Reinforcement |