RATE BASE

1. INTRODUCTION

This exhibit provides a comparison of 2018 Board Approved rate base with the 2018 historic year rate base as well as a forecast of Hydro One Transmission's rate base for the test years of 2020 to 2022 and a detailed description of each of the components.

The rate base underlying each of the test years' revenue requirements includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are calculated as gross plant in service minus accumulated depreciation and contributed capital[1]. Working capital includes an allowance for cash working capital as well as materials and supply inventory.

2. COMPARISON OF RATE BASE TO BOARD APPROVED

Table 1 below compares 2018 costs to the 2018 Rate Base approved by the OEB in its Decision on Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160.

[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

Table 1: 2018 Board-approved versus 2018 Historic Year Rate Base

($ Millions)

Rate Base Component	2018 Historic Year	2018 Board-approved	Variance
Mid-Year Gross Plant	17,630.8	17,537.1	93.7
Less: Mid-Year Accumulated Depreciation	(6,481.9)	(6,416.3)	(65.6)
Mid-Year Net Utility Plant	11,148.9	11,120.8	28.1
Cash Working Capital	14.1	15.0	(0.8)
Materials & Supply Inventory	11.5	12.2	(0.7)
Total Rate Base	**11,174.6**	**11,148.0**	**26.6**

Total rate base in 2018 is in line with the OEB-approved total, within 0.24% of the amount.

3. UTILITY RATE BASE

Utility rate base for the transmission system for the test years is filed at Exhibit C, Tab 4, Schedule 1. The calculation of Net Utility Plant is provided at Exhibit C, Tab 4, Schedule 2 and 3.

Hydro One Transmission's forecast rate base for the test years 2020-2022 is shown in Table 2.

Table 2: Transmission Rate Base ($ Millions)

Description	Bridge	Test		
	2019	2020	2021	2022
Mid-Year Gross Plant	18,591.6	19,489.3	20,598.5	21,829.8
Mid-Year Accumulated Depreciation	(6,810.4)	(7,151.2)	(7,544.0)	(7,953.3)
Mid-Year Net Plant	11,781.2	12,338.1	13,054.5	13,876.5
Cash Working Capital	22.1	24.4	26.6	27.8
Materials and Supply Inventory *	11.7	12.0	12.2	12.4
Transmission Rate Base	**11,815.0**	**12,374.5**	**13,093.3**	**13,916.7**

** Average Materials and Supply Inventory*

The mid-year gross plant balance reflects the capital expenditures and in-service additions forecast for the bridge and test years. The capital expenditures are described in detail in Sections 3.1 through 3.3 of the TSP, and the in-service forecast is outlined in Exhibit C, Tab 2, Schedule 1.

Table 3 below provides historical and bridge year continuity of total fixed assets. The growth in gross plant primarily reflects the in-service additions made to Hydro One Transmission's rate base during the period from 2015 to 2018.

Table 3: Continuity of Fixed Assets Summary - Rate Base ($ Millions)

Description	Historic Years			
	2015	2016	2017	2018
Opening Gross Asset Balance	14,805.9	15,398.1	16,274.2	17,076.7
In-Service Additions	652.3	897.5	864.2	1,135.6
Retirements	(40.4)	(13.0)	(47.2)	(10.9)
Sales	(19.8)	(7.5)	(11.8)	(15.9)
Transfers / Other	0.0	(0.8)	(2.7)	(0.5)
Closing Gross Asset Balance	**15,398.1**	**16,274.2**	**17,076.7**	**18,185.0**

Table 4 provides the forecast continuity of total fixed assets for the test years.

Table 4: Forecast of Fixed Assets Summary - Rate Base ($ Millions)

Description	Bridge	Test		
	2019	**2020**	**2021**	**2022**
Opening Gross Asset Balance	18,185.0	18,998.1	19,980.4	21,216.6
In-Service Additions	950.7	1,037.1	1,297.7	1,293.0
Retirements	(120.1)	(36.1)	(40.6)	(45.8)
Sales	0.0	0.0	0.0	0.0
Transfers / Other	(17.6)	(18.7)	(21.0)	(20.6)
Closing Gross Asset Balance	**18,998.1**	**19,980.4**	**21,216.6**	**22,443.1**

In-service additions reflect the placing of in service of Hydro One Transmission’s capital programs and projects and are discussed in Exhibit C, Tab 2, Schedule 1. These programs and projects are described in detail in Section 3.3 of the TSP.

The retirement of assets over the test years includes transmission plant equipment, meters and computer software. In 2019, phases of Hydro One’s SAP Cornerstone project become fully depreciated and were retired.

Transfers / Other over the period reflect movement between the strategic spares inventory and fixed assets. Also included are OPEB costs that are not being capitalized and which are instead captured in a deferral account until the OEB makes a determination on the appropriate treatment of OPEB costs.

4. CASH WORKING CAPITAL

In 2017, Hydro One Transmission retained Navigant Consulting Inc. to undertake a lead-lag study. The results of the new Navigant study and the provision for working capital for the 2020 through 2022 test years are incorporated.

The Cash Working Capital requirement for the transmission system includes the following factors:

- the forecast of OM&A;
- capital and income taxes; and
- the net lead-lag days determined.

The application of the methodology from the lead-lag study results in a net cash working capital requirement including the impact of HST, as shown in Exhibit C, Tab 5, Schedule 1, Attachment 1, Table 8 and Exhibit C, Tab 5, Schedule 2. Hydro One has calculated the 2020 test year cash working capital allowance to be $24.4M. Table 5 is a summary of total cash working capital allowance for test years 2020 to 2022.

Table 5: Total Cash Working Capital Allowance ($ Millions)

	Test		
	2020	**2021**	**2022**
Cash Working Capital	24.4	26.6	27.8

5. MATERIALS AND SUPPLY INVENTORY

In addition to cash working capital, the other component of working capital is materials and supply inventory. The average annual materials and supply inventory balances are $12.0 million for 2020, $12.2 million for 2021 and $12.4 million for 2022. Materials and supply inventory is discussed in further detail in Exhibit C, Tab 6, Schedule 1.

IN-SERVICE ADDITIONS

1. INTRODUCTION

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use by Hydro One Transmission customers. The in-service additions vary from capital expenditures due to the multi-year nature of capital projects with defined in-service dates.

Hydro One's in-service addition plan is developed by combining the best forecast available for all projects within its transmission portfolio that have assets planned for capitalization during the test years. Projects in execution encounter many challenges during execution such as outage constraints, external approvals, material delivery, site conditions, evolving customer needs, changing priorities and emergent investments. These project challenges may result in changes to the timing of in-service additions.

Table 1 provides an overview of Hydro One Transmission's in-service additions over the 2014 to 2018 period and the test years.

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

	Historical																				
	2014			**2015**			**2016**					**2017**			**2018**			**Bridge**	**Test**		
	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.

In 2016, Hydro One placed $910.2 million in-service to achieve the Ontario Energy Board ("OEB")-approved cumulative 2014 to 2016 in-service additions of $2,357.9 million[1]. The 2016 actuals are in-line with the 2016 "Bridge Projected" in-service capital additions included in EB-2016-0160, Exhibit D1, Tab 1, Schedule 2, Table 1 with a variance of $1.5 million dollars (Bridge Projected for 2016 equals $911.7 million).

Throughout 2017 and 2018, Hydro One achieved $2,032.6 million of in-service additions which is within 1% of the OEB-approved plan total for those years, demonstrating its ability to achieve results very close to target at a portfolio level.

Hydro One is committed to achieving in-service capital additions at a portfolio level over the test years by continuing to improve its project delivery model. Hydro One's capital work execution strategy is described in detail in Exhibit B, Tab 2, Schedule 1, which outlines how Hydro One intends to accomplish the forecast level of in-service additions.

2. PERFORMANCE ANALYSIS 2017-2018

In EB-2016-0160, the OEB directed Hydro One to provide a report on its performance in the execution of the capital program relative to plan. This report is attached as Attachment to this Exhibit and includes a detailed performance analysis of in-service additions for 2017 and 2018.

As described in TSP Section 2.1, the development of an investment plan must be done in a manner that is flexible enough to respond to changing and unforeseen circumstances. This is due to the dynamic nature of capital projects and changing conditions that must be

[1] See Exhibit B, Tab 2, Schedule 1.

managed at all phases of the project lifecycle. These changes are reflected as project logistics and schedule delays, prudent cost/scope increases or a valid redirection of projects to address new risks related to development, compliance or anticipated expenditures associated with equipment failures. Although these changes have an impact on an individual project's in-service addition forecast, Hydro One makes tactical adjustments to minimize the overall impact to the transmission portfolio.

Figure 1 and 2 below show how Hydro One performed in 2017 and 2018. It includes the following variance categories:[2]

a) Emergent Needs
Emergent needs are investments that Hydro One made and in-serviced during the 2017-2018 period in response to a change of priority due to equipment condition or failure.

b) Project Delivery Issues
Project delivery issues represent timing delays that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, project plans are adjusted to accommodate the change and mitigate the overall impact to the project cost and schedule. This can change the year in which the project goes in-service but does not typically change the in-

[2] Variance explanations are assigned to projects and programs that met the criteria the OEB provided in EB-2016-0160 for the variance report attached to this exhibit (i.e. "projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years"). The "Other" category in the waterfall chart below includes all projects and programs that fell below the $3 million threshold.

service amount. Some of the main causes for delays are outage delays or cancellations, material delivery and logistics issues and customer needs.

c) Preliminary Project Definition

Preliminary project definition variances naturally arise as a project's scope, estimated budget and schedule are refined as the project moves from the high-level planning phase to the detailed execution phase. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known later in the project lifecycle. As is described in Hydro One's capital work execution strategy (Exhibit B, Tab 2, Schedule 1), Hydro One has improved the planning and estimating process that iteratively defines the scope, cost and schedule for its investments based on the project phase and information available at the time. As a result, the in-service addition amounts and project expenditures are more accurate, although changes may still arise during the planning process. Drivers of change include:

- prudent scope changes or additions made as project plans mature;
- assumptions made in earlier project phases that are later clarified as site-specific conditions are addressed during detailed execution; and
- risks that either materialize or are mitigated during execution that impact the amount of contingency spent.

d) Accelerated Investments

Accelerated investments are projects that are completed sooner than planned as a result of opportunities that arise during the project lifecycle. Hydro One's redirection process, as described in section 2.1 of the TSP, allows the company to adjust its work delivery when changes occur. In some cases, this results in the acceleration of work when resources are redirected from another delayed project. Investments may also be accelerated where the project was executed more efficiently than anticipated or if an opportunity arises such as an outage becoming available. As well, as work plans are defined, opportunities to capitalize portions of completed work may arise that allow for reduction of carrying costs (interest charges).

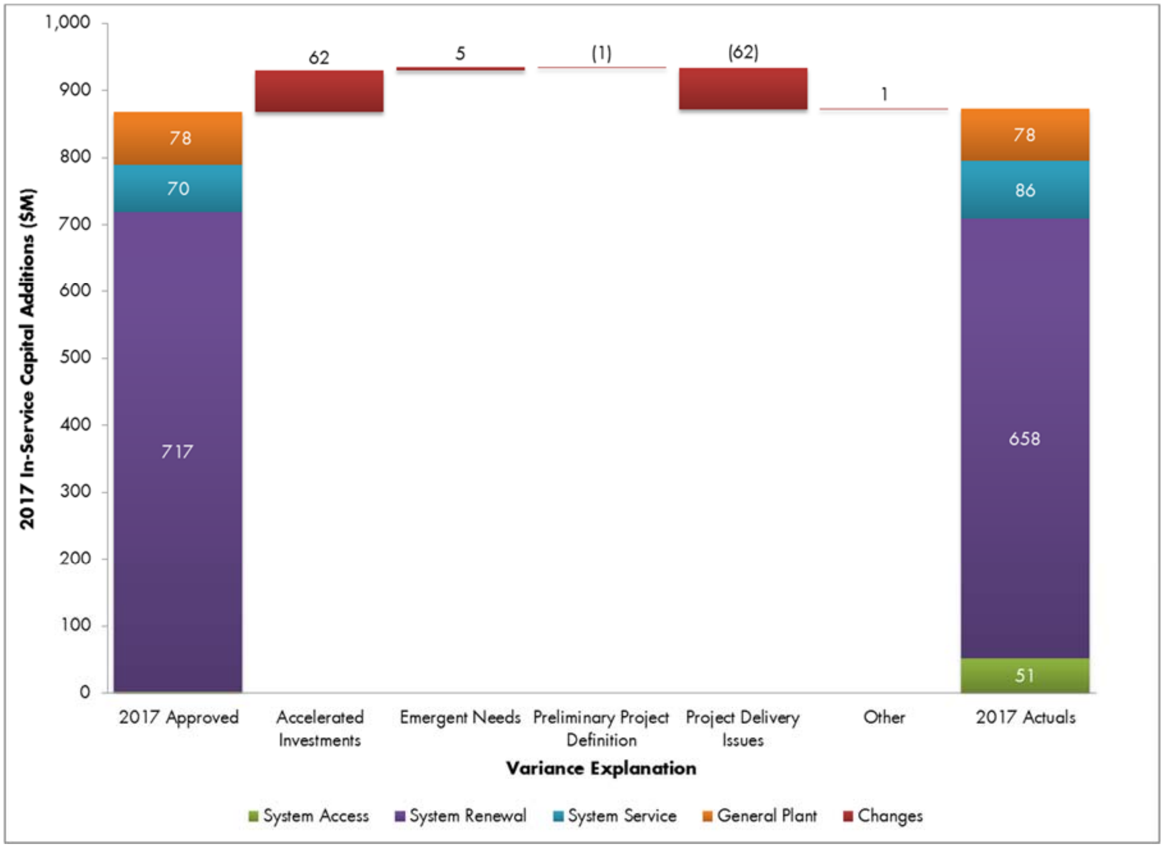

Figure 1 - 2017 Performance Analysis

On a net basis, there were two major categories of variances in 2017: a negative variance of $61 million owing to project delivery issues and an offsetting positive variance of $62 million owing to accelerated investments.

The negative variance arose primarily from delivery issues on two projects: (i) S43 – National Research Council ("NRC") Transmission Station integrated DESN replacement, where design and construction issues, along with an unexpected transformer failure, required changes to the project schedule and led to a delay in-servicing the planned $26.3 million project from 2017 to 2018; and (ii) S47 – St. Isidore Transmission Station re-investment, where design issues led to construction and commissioning delays which deferred the planned in-service addition of $27.8 million from 2017 to 2018.

The negative variances were largely offset by the acceleration of D14 – Supply to Essex County Transmission Reinforcement at Leamington Transmission Station, where the project was accelerated to address the imminent failure of a critical transformer at Kingsville Transmission Station. This resulted in the company putting the $43.7 million project into service ahead of schedule in 2017 rather than 2018 as planned.

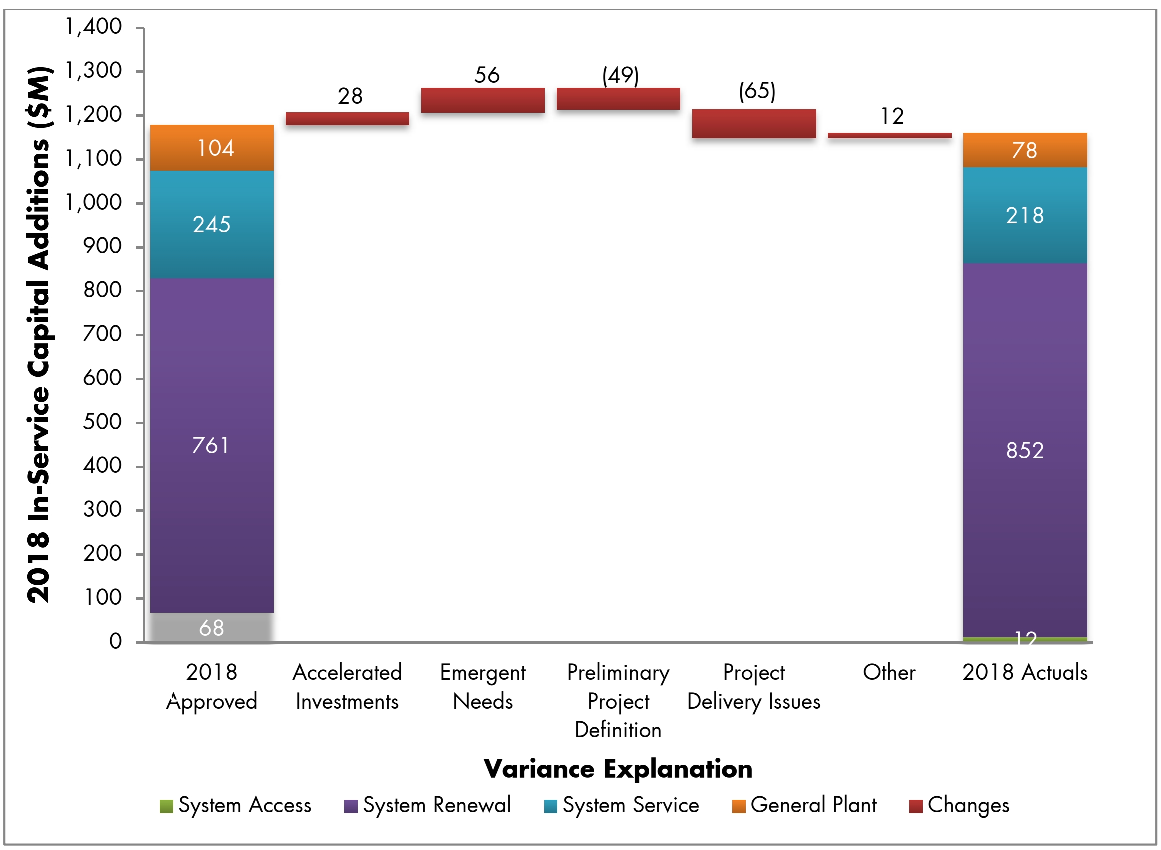

Figure 2 - 2018 Performance Analysis

On a total (capital and in-service additions) net basis, the following categories in 2018 drive a positive variance: $28 million variance owing to accelerated investments in project work, and a $56 million variance owing to emergent needs for both program and project work. Offsetting negative variances include $49 million owing to the preliminary project definition category for both program and project work, and $65 million owing to project delivery issues for both program and project. Looking at the overall portfolio of projects, below is a summary of the largest positive and negative variances for the year.

In 2018, the largest negative variances arose from two projects in the Development and Sustaining Capital categories: (i) D14 – Supply to Essex County Transmission Reinforcement at Leamington Transmission Station at $44.4 million, which was accelerated and placed in-service in 2017; and (ii) S83 - High Voltage Underground Cable line replacement (H7L/H11L) where failure of a companion cable delayed the outage required to proceed with the project work for in-servicing $35.3 million of the project. The negative variances were then largely offset by two projects in the Sustaining Capital category, which experienced in-servicing delays in 2017 and were brought forward into 2018: (i) S47 - St. Isidore Transmission Station reinvestment with a positive variance of $25.7; and (ii) S43 – National Research Council ("NRC") Transmission Station integrated DESN replacement with a positive variance of $23.8 million.

Notable variances in the remaining categories include the following: For emergent needs, at Kenilworth Transformer Station, one transformer was in degrading condition and required immediate replacement, adding in-service capital of $9.6 million. Another important factor that contributed to emergent needs included the fire incidents that occurred at Finch transformer station and Minden transformer station, where immediate work was required to replace the damaged transformers and other auxiliaries. In the preliminary project definition category, the largest contributor to the negative variance

($16.2 million) was in Facilities Accommodation Improvements, where reprioritization caused the work to move into 2019.

Variances are described in detail at a project and program level in Exhibit C, Tab 2, Schedule 1, Attachment 1 – Report on Capital Performance.

3. IN-SERVICE ADDITIONS IN 2020 TO 2022

In-service capital additions will increase 9% in 2020 as compared to the 2019 projected amount and is generally in-line with the 2018 Plan. The in-service additions increase from 2020 to 2021 by 25% and then remain flat in 2022.

System Access in-service capital additions will peak in 2020 primarily due to the completion of Leamington DESN2.

System Renewal in-service capital additions will remain consistent with 2018 approved levels in both 2019 and 2020. Amounts in 2021 and 2022 will increase significantly due to the completion of Load Station Transformer Replacement Projects (SR-05) and Transmission Line Refurbishment projects for both: End of Life ACSR, Copper Conductors & Structures (SR-19) and Near End of Life ACSR Conductor (SR-20); as well as an increase in the Overhead Lines Component Refurbishments and Replacements category.

System Service in-service additions will decrease significantly in 2019 as compared to the 2018 approved amount primarily due to the completion of the Clarington TS project in 2018. In-service amounts for remaining test years will reach their peak in 2021 with the partial completion of the East West Tie Connection (station work only) (SS-04) and Barrie Area Transmission Upgrade (SS-09). The in-service additions in this category drop off slightly in 2022 with the remainder of the East-West Tie Connection work being completed along with the completion of several mid-sized projects including Alymer-Tillsonburg Area Transmission Reinforcement (SS-12) and Merivale TS to Hawthorne TS: 230kV Conductor Upgrade (SS-06).

General Plant in-service capital additions will remain at a relatively consistent level on average with the exception of 2021 with the completion of the Integrated System Operations Centre (GP-01).

The associated capital expenditures in 2020-2022 are described at the program and major project level in the TSP at section 3.2. All projects with spending greater than $3 million in one of the test years are described in more detail in the ISD exhibits. The following is a list of in-service capital additions over the test years of greater than $100 million:

- Air Blast Circuit Breaker Replacement Projects (SR-01) ($441.5 million over 2020 to 2022);
- Station Reinvestment Projects (SR-02) ($406.7 million over 2020 to 2022);
- Load Station Transformer Replacement Projects (SR-05) ($225.6 million over 2020 to 2022);
- Transmission Station Demand and Spares and Targeted Assets (SR-09) ($120.6 million over 2020 to 2022);
- Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures (SR-19) ($355.3 million over 2020 to 2022);
- Transmission Line Refurbishment - Near End of Life ACSR Conductor (SR-20) ($206.7 million over 2020 to 2022);
- Wood Pole Structure Replacements (SR-21) ($151.5 million over 2020 to 2022);
- Transmission Line Insulator Replacement (SR-25) ($204.2 million over 2020 to 2022);

- East-West Tie Connection (SS-04) ($155.0 million over 2020 to 2022);

CAPITAL PROGRAM PERFORMANCE REPORT – 2017 AND 2018

INTRODUCTION

In its decision in EB-2016-0160 dated September 28, 2017 (the "Decision"), the Ontario Energy Board ("OEB") directed Hydro One to deliver a report describing its performance in the execution of its capital program relative to plan ("Capital Program Performance Report") as part of this Application.

In setting Hydro One's capital envelope, the OEB stated that "[t]he reason for approving a capital envelope, as opposed to a specific set of projects, is that Hydro One has the judgement, expertise and tools to determine what can be accommodated within that envelope considering both work priority and execution capability".[1]

During the subsequent draft rate order decision issued November 9, 2017 (the "DRO Order"), the OEB questioned the way Hydro One allocated OEB determined capital reductions at the sub-category and program level. The OEB noted that Hydro One had not provided a complete rationalization of its proposed allocation of capital reductions and directed that the Capital Program Performance Report also include information about how and why the company allocated reductions in capital spending the way it did and to provide information on the impact of these reductions to in-service additions.

[1] Decision at p. 31

This report responds to the OEB's direction and includes the follow analyses:

a) Reductions to Proposed Capital Expenditures – a description of actions taken by Hydro One to allocate the capital reductions and an explanation of how the allocations meet the intent of the Decision[2]
b) Impact on In-service Additions – a description of how and when capital reductions will impact in-service additions[3]
c) Performance Reporting – a description of Hydro One's overall performance in the execution of its capital program relative to plan showing:

    i. Performance at the sub-category level for capital expenditures and in-service additions; and
    ii. Performance at the projects and programs level for projects and programs with total budgeted cost greater than $3 million completed in 2017 and 2018, the status of each project and an explanation of any variances regarding scope, cost or schedule.[4]

The information in this report is current as of December 31, 2018. In this regard, Hydro One notes that some projects can take years to complete and be placed in-service and at times, an operational need to add, delete or adjust the timing of particular work such that spending on the specific capital categories within a period will vary from forecast. As a result, Hydro One's performance of forecast capital expenditures and in-service additions relative to actuals can only be assessed over the entire project period because funds expended and projects completed may move between years. In other words, even if

[2] DRO Order, p. 8
[3] DRO Order, p. 8
[4] Decision, p. 31

Hydro One invested more or less than the amount forecast in a given year, no overspending or underspending would have occurred within the rate period until the total amount invested exceeded the total investment forecast over the entire period. This is particularly so in the present application related to the custom incentive rate period and, as such, should be a consideration for any future period reporting arising from this application. Furthermore, as noted in Section 5 below related to the impact of capital expenditure changes on in-service additions, because of the timing lag between capital expenditures and in-service additions, annual analysis of how one impacts the other is of little assistance and must be considered over a period of time such as the custom incentive rate period.

Section 1 of this report summarizes the relevant procedural history giving rise to this report. Section 2 explains the terminology used in this report. Section 3 provides a description of the practical realities of executing a large capital work program. Section 4 describes the steps Hydro One took to reduce its capital spending in a manner consistent with the Decision. Section 5 describes the impact of capital reductions on in-service additions. Section 6 describes Hydro One's performance relative to plan at the sub-category level for capital spending and in-service additions and provides a status update on large projects and programs with explanations for material variances that arose in 2017 and 2018.

1. PROCEDURAL HISTORY

In its EB-2016-0160 decision dated September 28, 2017 (the "Decision"), the OEB directed Hydro One to prepare a report for this Application detailing its overall performance in the execution of its capital program relative to plan (the "Capital Program Performance Report")[5] as follows:

> *The OEB requires Hydro One, as part of its next transmission rate application, to provide a report detailing its overall performance in the execution of the capital program relative to plan. More specifically, the report should show the performance at the program level in terms of overall expenditures and in-service additions compared to the approved plan. In addition, for major projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years, the report should show the status of each project and an explanation of any variances regarding scope, cost or schedule.*[6]

The OEB approved a capital envelope of $950 million for 2017 and $1,000 million for 2018. In doing so, the OEB explained that it approved a capital envelope instead of a specific set of projects because Hydro One had the judgement, expertise and tools to determine how to work within that envelope.[7]

During the subsequent draft rate order process, the OEB reviewed Hydro One's proposed allocation of the OEB determined capital envelope reductions particularly in the areas of sustaining and development capital. In the DRO Order issued November 9, 2017, the OEB included an additional requirement that the Capital Program Performance Report describe what Hydro One did to meet the intent of the Decision regarding capital reductions and how those actions affected in-service additions:

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[5] Decision at p. 31 and 117
[6] Decision at p. 31 and 117
[7] Decision at p. 31

> *The OEB finds that the information provided by Hydro One, both in the DRO and the DRO reply submission, is insufficient to enable the OEB to determine whether the proposed changes in capital spending forecast are consistent with the Decision.*
>
> *[…]*
>
> *The OEB directs Hydro One to seek further opportunities to address the concerns raised in the OEB Decision regarding sustaining capital and to report on the specific actions taken and their impact as part of the status report which was required by the OEB in section 4.4 of its Decision. This part of the report should describe how the actions taken and associated results are consistent with the wording and intent of the Decision.*
>
> *[…]*
>
> *For the same reasons described in the previous section, the OEB does not have sufficient information to judge the adequacy of the proposed ISA reductions. The status report requested by the OEB in section 4.4 of its Decision already requires Hydro One to report on actual ISA compared to plan. In addition, the OEB directs Hydro One to specifically describe in that report how the actions taken by Hydro One to meet the intent of the Decision regarding capital reductions affected ISA.*

Subsequently, on November 16, 2017, Hydro One submitted an updated Draft Rate Order ("DRO Update") and provided the OEB with a further explanation about how it implemented capital reductions in the draft rate order. Hydro One explained reductions to its DRO Forecast capital expenditures and why the company had selected certain projects or programs over others. In particular, Hydro One committed to slowing the pace of its tower coating and shieldwire replacement programs and deferred line refurbishment projects. The company described the limitations that made significant reductions to ongoing stations work imprudent. Hydro One also explained that reductions made in the development capital category were largely driven by changes in customer demand and project forecasts.

2. DEFINITIONS

This section explains: (i) the three points in time at which numbers are compared for the purpose of calculating variances; and (ii) the four levels at which capital expenditure and in-service addition amounts are provided and the OEB categories used for the purposes of this report.

2.1 RELEVANT POINTS IN TIME

This report addresses Hydro One's capital expenditure and in-service addition amounts at three points in time:

- Proposed amounts – Capital expenditures and in-service additions as proposed in its pre-filed evidence for EB-2016-0160;
- DRO Forecast amounts – Capital expenditures and in-service additions forecasted in Hydro One's updated draft rate order submissions dated November 16, 2017; and
- Actual amounts – Capital expenditures and in-service additions actually incurred as of December 31 of the respective year.

2.2 GRANULARITY OF REPORTING

In the Decision and during the DRO process, various terms were used to describe the level at which capital expenditures and in-service variances were reported. This report adopts the terminology that was used, for the most part, during the DRO process. Capital expenditures and in-service additions are reported at four levels of granularity as follows:

- Envelope – The envelope level includes all capital expenditures and in service additions;
- Category – The category level ("category") includes sustaining capital (lines), sustaining capital (stations), development capital, operations and common corporate costs. Hydro One used these categories rather than the new OEB categories of system renewal, system access, system service and general plant to maintain consistency with the way numbers were displayed in EB-2016-0160;[8]
- Sub-category – The level below the category level, for example, 'power transformers' is a sub-category of the sustainment capital (stations) category; and
- Project/Program – The project and program level includes the individual projects and programs that comprise a sub-category, for example, the transformer replacement program at Dymond Transmission Station is a program within the power stations sub-category.

3. EXECUTION OF A CAPITAL PROGRAM

Hydro One's transmission capital work program is comprised of investments designed to refurbish existing assets as well as install new assets to address system needs. The practical reality of managing a large capital program is that projects can take many months or sometimes years to complete, circumstances may change throughout the course of the project and plans must adapt accordingly. As a consequence, in-service

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[8] Note, since the DRO process, Hydro One re-assigned the sub-category "operating infrastructure" from the common corporate costs category to the operations category.

additions may lag behind capital expenditures and variances between planned and actual capital expenditures and in-service additions may arise for a variety of reasons and must be managed through the planning and redirection process. This section describes some of the factors that can impact the execution of a capital program, four main reasons for variances, and what Hydro One does to mitigate variances when they arise.

3.1 FACTORS IMPACTING WORK EXECUTION AND VARIANCES

The planning process can impact the amount of capital expenditures and the timing of in-service additions. To make prudent decisions about the best solution for a defined asset or development need, a robust planning process is used to consider alternatives and their relative cost at a high level before entering a detailed project definition phase. Hydro One's process is described in section 2.1 of the TSP. This process is necessary in order to triage different investment opportunities as quickly as possible and build a long term plan without committing significant cost until alternatives have been considered. As part of the project definition phase, risks are identified and analysed that can materially impact the project cost or schedule.[9]

As the project shifts from the planning phase to execution, site specific information becomes available, project plans are refined, and identified risks may materialize which may change the project timeline or forecast, as further described in Exhibit B, Tab 2, Schedule 1. This can give rise to variances and requires that the company redirect its resources as efficiently as possible.

[9] The project definition phase is described in Exhibit B-02-01

The type of work may also have a bearing on capital expenditures and in-service addition variances. Hydro One's capital work plan is comprised of projects and programs. Programs include repeatable work on a specific asset type, like pole replacement. Projects are stand-alone jobs with a discrete beginning and end, like the construction of a new transmission station. As described in the paragraph above, project plans are refined throughout the planning process as the company gathers information about outage availability, worksite conditions and specialized labour and equipment requirements among other things. This can lead to variances between the initial and final project scope and budget. This type of variance is less common for programs which consist of more predictable, repetitive work. Large projects often require extended outages (or in the alternative, a work-around) which can be challenging to coordinate[10] whereas programs typically require shorter outages. A change in outage availability may significantly delay a project's in-service date particularly if an outage window is rarely available, whereas it may delay a program by only a day or so. Conversely, a change in the unit cost of a key component may have a greater impact on a program than a project because programs rely largely on unit cost-based pricing.

The category of work can also impact execution and variances. Development work, for example, is unique in that it is largely driven by third parties wishing to expand capacity of the transmission system, such as a Local Distribution Company ("LDC") requesting additional feeders to connect more load. Hydro One must complete these requests within an OEB-mandated timeline. The company has limited flexibility to defer this work and in some cases may need to prioritize it to meet timelines by deferring other work. Variances

[10] Exhibit B-02-01 – Work Execution Strategy (Capital) explains Hydro One's work execution strategy and delivery process

within this category are often driven by third parties, for example, a wind farm may need to delay its connection date or cancel its project altogether.

Sustainment work, on the other hand, is highly dependent on successfully scheduling and obtaining outages ultimately authorized by the Independent Electricity System Operator ("IESO") as a function of real-time system conditions. For this reason, project plans may change significantly if outages are cancelled (seasonal outage windows, customer maintenance schedules/production peak times, etc.) hence the amount of work completed (capital expenditure) and the in-service addition forecast may change.

3.2 VARIANCE EXPLANATIONS

Variances may occur during the delivery of the capital work program for a variety of reasons. Variances may be summarized into four major categories as follows: emergent needs, project delivery issues, preliminary project definition and accelerated investment. These categories are used to identify the reasons for variances at the project and program level and are defined below.

3.2.1 EMERGENT NEEDS

Emergent needs are investments that Hydro One made and in-serviced during the 2017-2018 period in response to a change of priority due to equipment condition or failure.

3.2.2 PROJECT DELIVERY ISSUES

Project delivery issues represent timing delays that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, project plans are adjusted to accommodate the change and mitigate the overall impact to the project cost and schedule. This can change the year in which the project goes in-service but does not typically change the in-service amount. Some of the main causes for delays are outage delays or cancellations, material delivery and logistics issues and customer needs.

3.2.3 PRELIMINARY PROJECT DEFINITION

Preliminary project definition variances naturally arise as a project's scope, estimated budget and schedule are refined as the project moves from the high-level planning phase to the detailed execution phase. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known later in the project lifecycle. Over the test period, Hydro One expects that this type of variance will make up a greater portion of total variances because the test period will include more projects in the early stages of planning.

As described in Hydro One's capital work execution strategy Exhibit B, Tab 2, Schedule 1, Hydro One has improved the planning and estimating process that iteratively defines the scope, cost and schedule for its investments based on the project phase and information available at the time. As a result, the in-service addition amounts and project expenditures are more accurate, although changes may still arise during the planning process. Drivers of change include:

- prudent scope changes or additions made as project plans mature;
- assumptions made in earlier project phases that are later clarified as site specific conditions are addressed during detailed execution; and
- risks that either materialize or are mitigated during execution that impact the amount of contingency spent.

3.2.4 ACCELERATED INVESTMENTS

Accelerated investments are projects that are completed sooner than planned as a result of opportunities that arise during execution. Hydro One's redirection process, as described in section 2.1 of the TSP, allows the company to adjust its work delivery when changes occur. In some cases, this results in the acceleration of work when resources are redirected from another delayed project. Investments may also be accelerated where the project was executed more efficiently than anticipated or if an opportunity arises such as an outage becoming available. As well, as work plans are defined, opportunities to capitalize portions of completed work may arise that allow for reduction of carrying costs (interest charges).[11]

3.3 MITIGATING VARIANCES

Hydro One implemented a number of initiatives and processes to prevent and better manage variances earlier in a project's lifecycle. These are described in Exhibit B, Tab 2, Schedule 1 and include the company's change management process and risk definition & management program.

When variances occur, they may be managed through the variance and redirection process described in Section 2.1.9.3 of the TSP. Variances caused by delays may be managed by accelerating other projects or programs and selecting work based, in part, on priority and maturity. Hydro One notes that some projects can take years to complete and be placed in-service and sometimes, there is an operational need to add, delete or adjust

[11] Hydro One currently includes partial in-service additions in its forecasts and project plans, however, this was not the case for all projects that were in-serviced in 2017 where they were developed using prior practices. For this reason partial in-servicing of assets gave rise to a variance in some instances.

the timing of work. As such, in-service addition variances are best assessed over the entire forecast period because projects may move between years.

4. ALLOCATION OF CAPITAL REDUCTIONS

This section explains how and why Hydro One allocated capital reductions the way it did during the DRO process. As part of its Decision, the OEB approved a capital envelope of $950 million for 2017 and $1,000 million for 2018, which required Hydro One to reduce its proposed capital expenditures by $126.1 million and $122.2 million respectively. During the DRO process, Hydro One proposed to allocate the capital reductions as shown in Table 1 below:

Table 1: Allocation of Capital Reductions at DRO Proceeding

	Capital Expenditures ($ millions)			
	2017		2018	
	Proposed	**DRO Forecast**	**Proposed**	**DRO Forecast**
Sustaining Capital (Stations)	537.5	541	496.2	537.5
Sustaining Capital (Lines)	239.3	203.7	345.9	257.9
Development Capital	196.4	131.4	170.2	94.9
Operations Capital	25.4	13	30.8	42.9
Capital Common Corporate	77.6	60.9	79.1	66.8
	Proposed	**OEB Approved**	**Proposed**	**OEB Approved**
Total Transmission Capital	**1,076.2**	**950**	**1,122.2**	**1,000**

In its Decision, the OEB questioned why Hydro One increased its proposed spending in sustaining capital (stations) when it had questioned the level of spending on certain programs in the sustaining capital category, particularly the pacing of the tower coating program and integrated station investments. In the DRO Order, the OEB directed Hydro One to "seek further opportunities to address the concerns raised in the OEB Decision regarding sustaining capital"[12] and sought further detail in this Report on how Hydro One allocated the capital reductions.

In its subsequent "DRO Update" dated November 16, 2017 which was submitted in response to the DRO Order, Hydro One addressed the points raised by the OEB in the DRO Order with an explanation about how it allocated capital reductions in the draft rate order for 2017 (where possible) and 2018 by providing the following additional information:

- In "Overhead Lines Refurbishment Projects, Component Replacement", the company reduced the tower coating and shieldwire replacement programs and its deferred line refurbishment projects.
- In "Integrated Stations", at the time the Decision was issued, 98% and 75% of the portfolios for 2017 and 2018, respectively, were already in execution. Cancelling those projects would result in significant inefficiencies and stranded costs. Deferring the remaining 25% of the 2018 "Integrated Stations" projects would negatively impact reliability. These projects include investments at Kingsville, Leaside, Cherrywood, Sheppard, Detweiler, Minden, Gage and Stanley transformer stations.
- Reductions in the Development capital forecast were largely driven by changes in customer demand and project forecasts. The Development projects most impacted are investments at Clarington TS (-$38 million), Lisgar TS (-$7 million), Runnymede TS (-$13 million) and Hanmer TS (-$8 million).

[12] DRO Order, p. 7

Figure 1 below is a waterfall graph showing how Hydro One proposed to allocate capital reductions in 2017 during the DRO process. The column on the left shows Hydro One's proposed capital expenditures as submitted in its application materials in EB-2016-0160. The column on the right shows Hydro One's capital expenditures after it allocated the OEB-determined reductions in the DRO process. The columns in the middle show the net changes at the OEB category level to allocate the capital reductions.

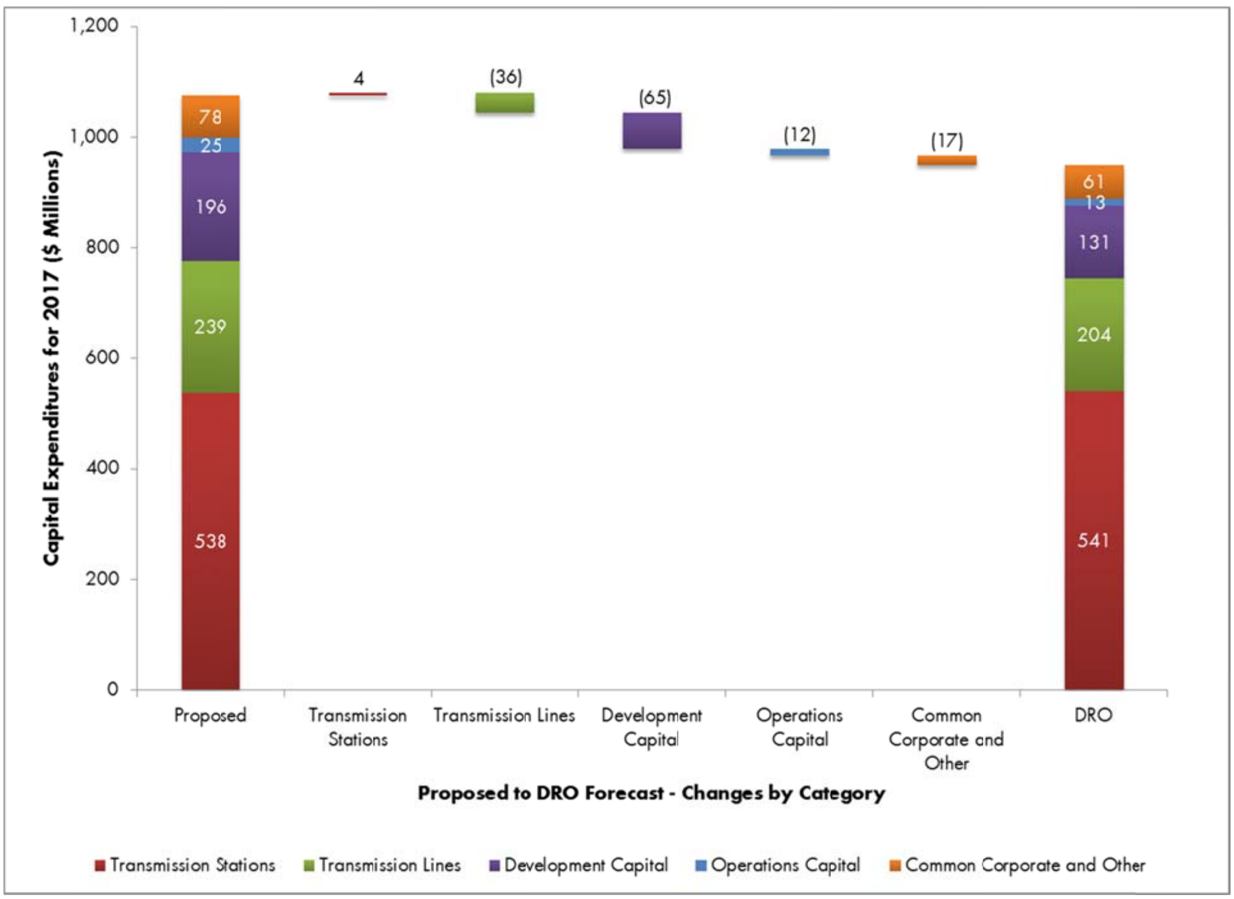

Figure 1: Capital Expenditure Reductions 2017 – Proposed to DRO

In 2017, Hydro One successfully operated within the reduced capital envelope as directed by the OEB, with a variance of $3.9 million. Hydro One was able to achieve this by operating conservatively in 2017 and not backfilling or redirecting work, in anticipation of the Decision. When the Decision was issued, Hydro One focussed on execution risk and made efforts to reduce capital expenditure without causing significant impact to projects in a mature state of execution. Additional considerations were given to material and contract timing as well as budgeted contingency funding. However, given the multi-year nature of capital projects and the timing of the Decision late in the year, it was not prudent to reduce sustaining capital spending. Indeed, the OEB recognized that, "given the date of its Decision, there is limited flexibility for Hydro One to adjust 2017 projects that are already underway or are at an advanced stage of planning".[13] Table 2 below shows Hydro One's performance at the OEB category level, comparing the capital expenditures the company proposed in its initial rate application materials ("Proposed"), the forecast it proposed during the DRO process ("DRO Forecast") and its actual performance ("Actuals").

Table 2: Capital Expenditures 2017, Proposed vs. DRO Forecast vs. Actual ($ milions)

	Capital Expenditures 2017		
	Proposed	**DRO Forecast**	**Actual**
Sustaining Capital	776.8	744.7	750.6
Development Capital	196.4	131.4	137.1
Operations Capital	25.4	13.0	10.8
Capital Common Corporate	77.6	60.9	55.3
Total Transmission Capital	**1,076.1**	**950.0**	**953.9**

A detailed description of Hydro One's Actual performance against its DRO Forecast is provided at the project and program level in section 6 below.

[13] DRO Order, p. 7

For 2018, the OEB directed Hydro One to reduce its capital expenditures by $122.2 million and to operate within a capital envelope of $1,000 million. During the DRO process, Hydro One described how it would reduce its Proposed capital expenditures to meet the OEB directed capital reductions. The company noted, among other things, that 75% of the 2018 Integrated Stations portfolio was already in execution at the time the Decision was issued and that cancelling these projects result in significant costs. Planned reductions are depicted at the OEB-category level in Figure 2.

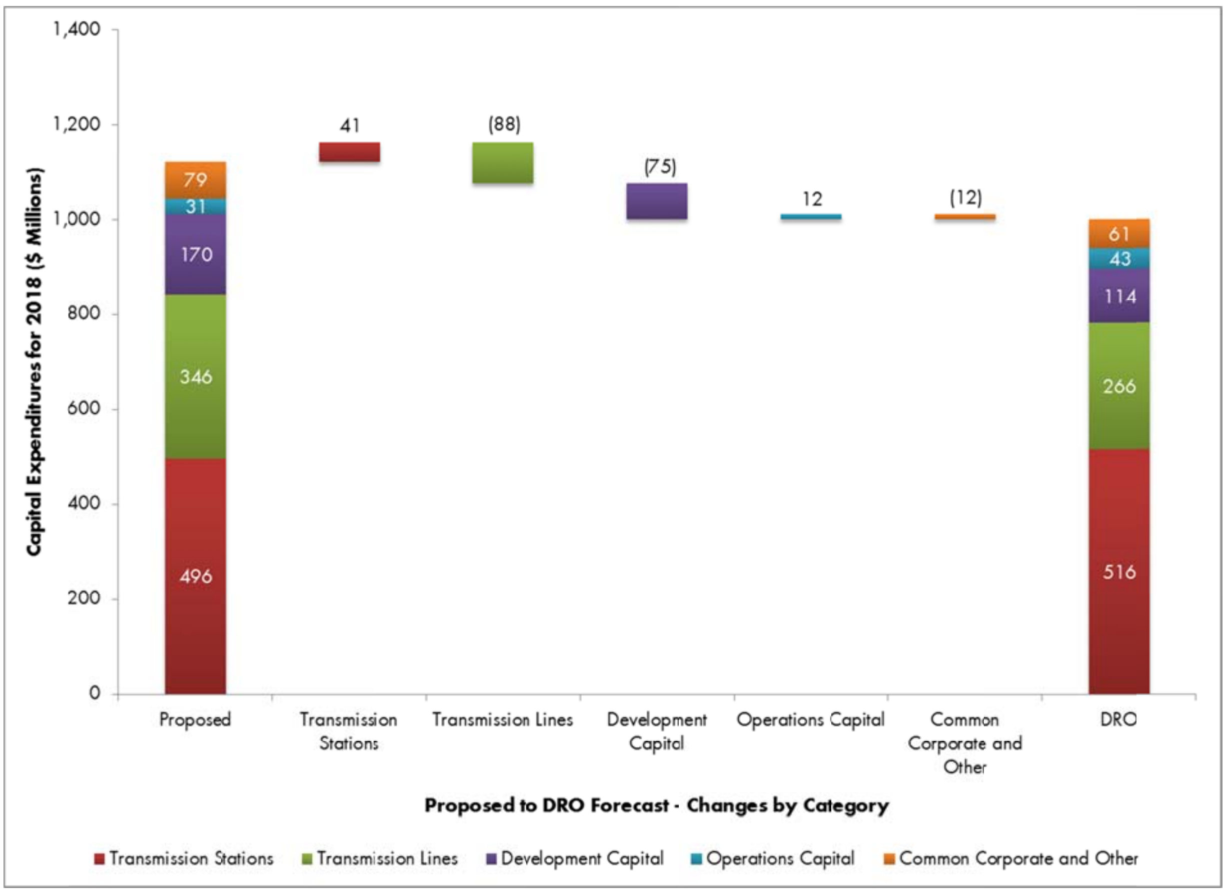

Figure 2: Proposed to DRO Capital Expenditure Comparison – 2018

5. IMPACT OF CAPITAL REDUCTIONS ON IN-SERVICE ADDITIONS

This section explains how and when the OEB's capital reductions will impact in-service additions. Transmission capital projects are often multi-year projects and many of the 2017 and 2018 in-service additions are or will be the result of projects initiated in earlier years. It would be imprudent, in some circumstances, to cancel a project in the execution phase for the purpose of delaying in-service additions to a later period. By way of example and as noted in the DRO Update, at the time the Decision was issued, 98% and 75% of the integrated stations sub-category for 2017 and 2018, respectively, was already in execution. Cancelling those projects would have resulted in significant inefficiencies, stranded costs and missed outcomes. As a result, the full impact of the 2017-2018 capital reductions will not be felt in the same year as the capital reduction. Rather, the impact will be felt in future years.

Figures 3 to 5 below indicate when Hydro One expects that 2017 and 2018 capital investments will be put into service over the following points in time: a) as proposed in the last rate application; b) upon implementation of the Decision and DRO; and c) as at December 31, 2017.

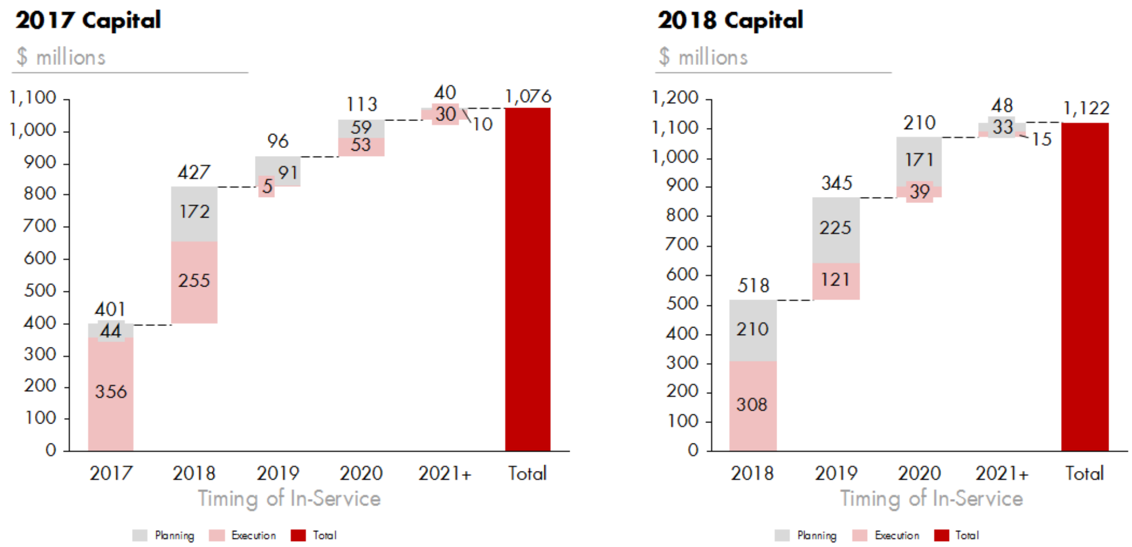

Figure 3: Capital Investments Proposed in Application

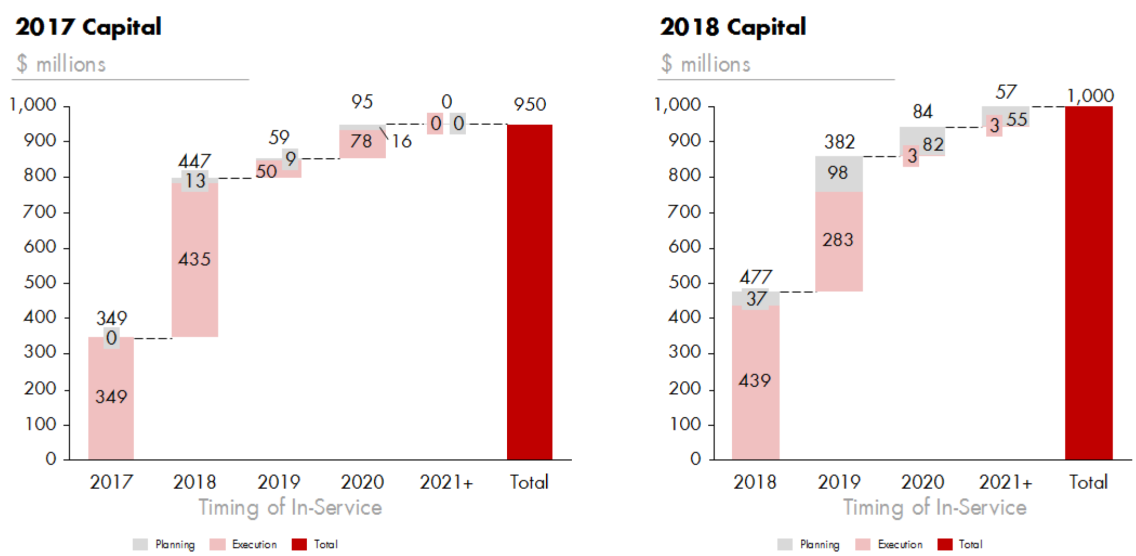

Figure 4: Capital Investments Adjusted during DRO Process

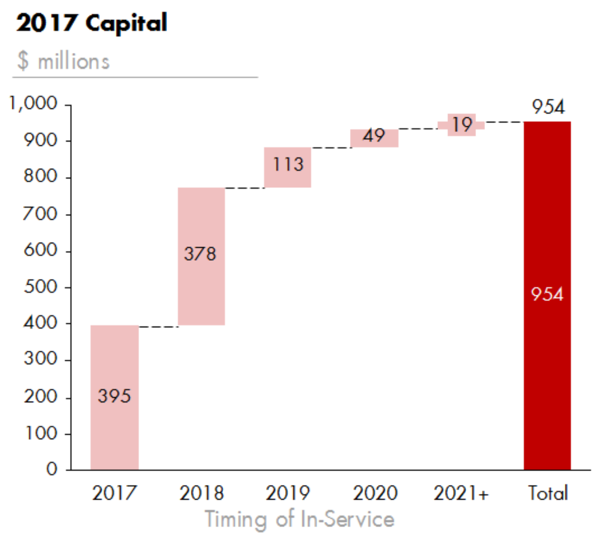

Figure 5: 2017 Actual Capital Investments

The OEB-directed capital reduction of $126 million in 2017[14] and $122 million in 2018 are projected to impact in-service additions as show in Table 3.

[14] Table 3 below includes 2017 Actual capital reductions which totaled ($123) million, $4 million less than the OEB-directed reduction of $126 million.

Table 3: Impact of Capital Reductions on In-Service Additions ($ millions)

	Timing of In-Service					Total
2017 Capital Investments	**2017**	**2018**	**2019**	**2020**	**2021+**	
Proposed	401	427	96	113	40	
Actuals	395	378	113	49	19	
Reduction by Year	-6	-49	17	-64	-21	**-123**
2018 Capital Investments		**2018**	**2019**	**2020**	**2021+**	
Proposed		518	345	210	48	
DRO		477	382	84	57	
Reduction by Year		-41	37	-126	9	**-121**
Total Reductions	**-6**	**-90**	**54**	**-190**	**-12**	**-244**

6. EXECUTION OF THE CAPITAL PROGRAM RELATIVE TO PLAN/DRO

This section of the report responds to the OEB's direction that Hydro One detail its actual performance compared to the approved plan:

> *The OEB requires Hydro One, as part of its next transmission rate application, to provide a report detailing its overall performance in the execution of the capital program relative to plan. More specifically, the report should show the performance at the program level* (i.e. sub-category) *in terms of overall expenditures and in-service additions compared to the approved plan. In addition, for major projects or programs with total budgeted cost greater than $3 million which are planned to be completed during the test years, the report should show the status of each project and an explanation of any variances regarding scope, cost or schedule.*[15]

[15] Decision at p. 31

6.1 INTRODUCTION TO 2017 AND 2018 VARIANCES

The 2017 variances are further described from section 6.2 to 6.5, and 2018 variances are described from section 6.6 to 6.9.

6.2 2017 CAPITAL EXPENDITURE AND IN-SERVICE ADDITION VARIANCES AT THE ENVELOPE LEVEL

On an envelope basis in 2017, Hydro One's performance was in-line with the OEB's direction in EB-2016-0160. The net variance between Draft Rate Order ("DRO") Forecast (defined below) and Actual (defined below) capital expenditures was $3.9 million and the net variance between DRO Forecast and Actual in-service additions was $4.6 million. Table 4, below, shows 2017 variances at the envelope level. Some variances exist at the category, sub-category and project and program levels (terms defined below) and these are explained in this report.

Table 4: Capital Expenditures and In-Service Addition Variances 2017 ($ millions)

Capital Expenditures 2017				In-Service Additions 2017		
Actuals	DRO Forecast	Variance		Actuals	DRO Forecast	Variance
953.9	950	0%		872.2	867.7	1%

Overall, there were two major categories of In-Service Addition variances in 2017: a negative variance of $61 million owing to project delivery issues and an offsetting positive variance of $62 million owing primarily to a single accelerated investment.

The negative variance arose primarily from delivery issues on two projects: (i) S43 – National Research Council ("NRC") Transmission Station integrated DESN replacement, where design and construction issues, along with an unexpected transformer failure, required changes to the project schedule and led to a delay in-servicing the $26.3 million project from 2017 to 2018; and (ii) S47 – St. Isidore Transmission Station re-investment, where design issues led to construction and commissioning delays which deferred the in-service addition of $27.8 million from 2017 to 2018.

The negative variances were largely offset by the acceleration of D14 – Supply to Essex County Transmission Reinforcement at Leamington Transmission Station, where the project was accelerated to address the imminent failure of a critical transformer at Kingsville Transmission Station. This resulted in the company putting the $43.7 million project into service ahead of schedule in 2017 rather than 2018 as planned.

6.3 2017 CAPITAL EXPENDITURE AND IN-SERVICE ADDITION VARIANCES AT THE CATEGORY AND SUB-CATEGORY LEVEL

Table 5 below shows Hydro One's performance at the sub-category level, or "the performance at the program level (i.e. sub-category level) in terms of overall expeinditures and in-service additions compared to the approved plan". [16]

[16] Decision at p. 31

1 **Table 5: 2017 Variances at the Sub-category Level**

	Capital Expenditures		Actual:DRO	In-Service Additions		Actual:DRO
	DRO	Actuals	($M)	DRO	Actuals	($M)
Sustaining Capital						
Transmission Stations						
Circuit Breakers	0.4	0.4	0	0.7	0.8	0.1
Power Transformers	1.1	0	-1.1	22.6	20.8	-1.8
Other Power Equipment	0.1	0	-0.1	1	2.3	1.3
Ancillary Systems	1.2	1.1	-0.1	2.6	0.5	-2.1
Station Environment	0.2	0.4	0.2	1.4	1.5	0.1
Integrated Station Investments	469	481	12	439.6	389.2	-50.4
TX Transformers Demand and Spares	28.2	26.8	-1.4	25.7	23.2	-2.5
Protection and Automation	27	20.9	-6.1	20.6	16.7	-3.9
Site Facilities and Infrastructure	13.8	13	-0.8	13.2	11.9	-1.2
Total Transmission Stations Capital	541	543.6	2.6	527.4	466.9	-60.4
Transmission Lines						
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	196.5	196.3	-0.2	200.5	199.9	-0.6
Underground Cables Refurbishment and Replacement	7.2	10.7	3.5	0.4	0.3	-0.1
Total Transmission Lines Capital	203.7	207.1	3.4	200.9	200.2	-0.7
Total Sustaining Capital	**744.7**	**750.6**	**5.9**	**728.3**	**667.1**	**-61.2**

Development Capital						
Inter Area Network Transfer Capability	36	36	0	1.3	16.7	15.4
Local Area Supply Adequacy	46.9	45.1	-1.8	55.7	57.9	2.2
Load Customer Connection	33.8	42.3	8.5	0.2	49.1	48.9
Generator Customer Connection	0	0.4	0.4	0.2	1.7	1.5
P&C Enablement for Distributed Generation	0.6	0.8	0.2	1.3	0.4	-0.9
Risk Mitigation	10.9	9.5	-1.4	10.3	9.1	-1.2
Power Quality	2.3	2.3	0	2.3	1	-1.3
TS Upgrades to Facilities Distribution Generation	0	0	0	0	0	0
Performance Enhancement	0	0	0	0	0.2	0.2
Smart Grid	0.9	0.7	-0.2	0.9	0.7	-0.2
Total Development Capital	**131.4**	**137.1**	**5.8**	**72.2**	**137**	**64.8**
Operations Capital						
Grid Operating and Control Facilities	7.7	6	-1.7	0.2	0.2	0
Operating Infrastructure	5.4	4.8	-0.5	4.4	3.3	-1.1
Total Operations Capital	**13**	**10.8**	**-2.2**	**4.5**	**3.4**	**-1.1**
Capital Common Corporate Costs and Other Costs						
Transport and Work, and Service Equipment	17.5	16.9	-0.6	17.6	16.9	-0.7
Information Technology (including Cornerstone)	34.4	32.8	-1.6	39.5	40.6	1.1
Facilities & Real Estate	9.1	6.7	-2.3	5.7	7.3	1.6
Other (including CDM)	0	-1.1	-1.1	0	0	0
Total Capital Common Corporate Costs and Other Costs	**60.9**	**55.3**	**-5.6**	**62.7**	**64.7**	**2**
Total Transmission Capital	**950**	**953.9**	**3.9**	**867.7**	**872.3**	**4.5**

6.4 2017 KEY VARIANCE DRIVERS

This section describes the main drivers of variance at the sub-category level where:

- The sub-category contains a project or program that meet the OEB criteria for inclusion in this report and has a material variance;[17] or
- There is a variance of more than +/- $3.0 million at the sub-category level, even if there are no projects or programs within the sub-category with material variances.

The projects or programs that drive the variance at the sub-category level are identified and the reasons for the variance are explained. Further detail on projects and programs with a total budgeted cost of greater than $3 million with planned or actual in-service additions in 2017 are included in section 6.3 below. This information included in this section 6.2 is in addition to what the OEB requested in EB-2016-0160 and is provided to give a clear picture of what drives variances during the execution of the capital program.

Net variances in the Power Transformer (Table 6) sub-category included a total capital expenditure variance of ($1.1) million and a total in-service addition variance of ($1.8) million. Project delivery issues on the Kirkland Lake T12 and T13 Replacement project were responsible for much of the variance in this sub-category. On this project, construction material contracts were less than forecasted, resulting in ($1.7) million capital expenditure and a ($1.8) million in-service addition variance and contributing to the overall variances in this sub-category.

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[17] A "material variance" includes scope, cost or date variances that surpass the thresholds set out in section 6.3 below and for which Hydro One has provided a variance explanation at the project or program level

Table 6: Power Transformers

Sustaining Capital - Transmission Stations - Power Transformers			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	1.1	0.0	-1.1
2017 In-service ($M)	22.6	20.8	-1.8

The integrated station investments sub-category is the largest in the Sustainment – Stations category (Table 7). These investments refurbish Hydro One's end of life transmission station assets. The net capital expenditure variance in this sub-category was $12 million or 3% of DRO Capex Forecast. The net variance is comprised of a number of project level adjustments. Overall, there were thirty one projects in this sub-category that met the OEB criteria for inclusion in this report. Of those, twenty projects had material variances within +/- $2 million that contributed to the overall net variance in this sub-category.

Two projects had larger in-service addition variances that were largely attributable to Project Delivery Issues as follows:

- NRC transformer station end-of-life asset replacement project – During refurbishment work at this station, one of the transformers unexpectedly failed which required a change to the project schedule and a redirection of resources to address the failure. In addition, design and construction issues associated with the MVGIS building also contributed to variances. Therefore, the schedule for this project was delayed to 2018, deferring $26.3 million in in-service addition amounts to 2018; and
- St. Isidore TS T3/T4 Project – Design issues arose during the execution of this project which caused construction and commissioning delays. As a result, the in-service date was delayed to 2018 along with a corresponding in-service addition of $27.8 million.

These projects were the major contributors to the overall in-service addition variance of ($50.4) million or (11%) to the DRO Forecast for this subcategory. As noted in the DRO Update, given the timing of the Decision and the fact that many of these projects were in the execution phase at the time, it was not prudent to make capital reductions in this category in 2017 or 2018.

Table 7: Integrated Station Investments

Sustaining Capital - Transmission Stations - Integrated Station Investments			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	469.0	481.0	12.0
2017 In-service ($M)	439.6	389.2	-50.4

Net variances in the Tx Transformers Demand and Spares sub-category included a total capital expenditure variance of ($1.4) million and a total in-service addition variance of ($2.5) million (Table 8). The key variance driver in this sub-category was the Spare Transformer Purchase (S53) program, where the company only purchased two transformers rather than five after three transformers failed their tests. This led to a capital expenditure variance of ($3.6) million and an in-service addition variance of ($3.3) million.

Table 8: Tx Transformers Demand and Spares

Sustaining Capital - Transmission Stations - TX Transformers Demand and Spares			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	28.2	26.8	-1.4
2017 In-service ($M)	25.7	23.2	-2.5

Capital expenditure and in-service addition variances in the Protection and Automation sub-category did not meet the OEB's criteria for providing a variance explanation because there were no projects greater than $3 million to be placed in-service in 2017 (Table 9). The overall capital expenditure variance in the sub-category was ($6.1) million, and there was an in-service addition variance of ($3.9) million. Much of the capital expenditure variance arose because the Power System Information Technology ("PSIT") Cyber Equipment End of Life program was combined with another project and moved to 2018. In-service addition and capital expenditure variances also arose because the NERC CIP low impact facility was deferred to accommodate other priority work.

Table 9: Protection and Automation

Sustaining Capital - Transmission Stations - Protection and Automation			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	27.0	20.9	-6.1
2017 In-service ($M)	20.6	16.7	-3.9

Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects represent the largest sub-category in the Sustainment – Lines category (Table 10). These investments refurbish Hydro One's end of life transmission line assets. There were material variances in this category at the project and program level that largely offset each other, giving rise to modest net variances of ($0.2) million for capital expenditures and ($0.6) million for in-service additions. Variances arose in respect of a number of projects and programs. By way of example:

- Capital expenditures and in-service additions for the Line Refurbishment – C22J/C24Z/C21J/C23Z project (S62) were under by ($4.1) million because construction material and equipment contracts cost less than forecasted.
- Capital expenditures for the Steel Structure Foundation refurbishments program (S77) were over by $0.9 million due to higher costs than expected on 500kV tower foundations.
- In-service additions for the D2L line refurbishment project (S63) were over by $2.0 million because in-line switch installations were added to the scope in order to take advantage of the available outages and minimize outage impact to customers.

As noted in the DRO Update, Hydro One slowed the pace of its tower coating and shieldwire replacement programs in this sub-category in 2017 in response to the OEB's comments in the Decision, intends to reduce its pace in 2018 relative to Proposed and has reduced its pace in 2019 and going forward as indicated in this rate application.

Table 10: Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects

Sustaining Capital - Transmission Lines - Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	196.5	196.3	-0.2
2017 In-service ($M)	200.5	199.9	-0.6

There was a total capital expenditure variance of $3.5 million and a total in-service addition variance of ($0.1) million in the Underground Cable Refurbishment and Replacement sub-category (Table 11). The capital expenditure variance may be attributed to a number of projects but the main variance arose on a cable replacement project where the scope was refined as the project moved from initial planning to detailed planning.

Table 11: Underground Cable Refurbishment and Replacement

Sustaining Capital - Transmission Lines - Underground Cables Refurbishment and Replacement			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	7.2	10.7	3.5
2017 In-service ($M)	0.4	0.3	-0.1

The overall in-service addition variance for the Inter Area Network Transfer Capability sub-category of $15.4 million can be attributed to accelerated investments (Table 12), specifically the Clarington TS: Build New 500/230kV Station project (D01), where $15.2 million of line work was capitalized ahead of plan.

Table 12: Inter Area Network Transfer Capability

Development Capital - Inter Area Network Transfer Capability			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	36.0	36.0	0.0
2017 In-service ($M)	1.3	16.7	15.4

Variances in the Local Area Supply Adequacy sub-category included a total capital expenditure variance of ($1.8) million and a total in-service addition variance of $2.2 million (Table 13). The Hawthorne Transmission Station – replacement of two transformers (D08) project had a material variance in respect of its schedule, where the in-service forecast date was moved from Q2 2020 to Q2 2021 owing to a number of competing projects at Hawthorne TS including a transformer failure.

Table 13: Local Area Supply Adequacy

Development Capital - Local Area Supply Adequacy			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	46.9	45.1	-1.8
2017 In-service ($M)	55.7	57.9	2.2

Capital expenditure variances in the Load Customer Connection sub-category can be attributed in large part to the completion of the Leamington Transmission Station (D14 – Supply to Essex County) project in 2017 ahead of schedule (Table 14). This was accomplished through the redirection of resources for the reasons described below and resulted in an in-year variance of $6.5 million, contributing to the overall variance for the category of $8.5 million.

In-service addition variances in this sub-category can also be attributed to the acceleration of the Leamington Transmission Station (D14 – Supply to Essex County), as $43.7 million was placed in service in 2017, ahead of schedule. This was done to address the imminent failure of a transformer at Kingsville TS, the only means of supplying electricity to customers in the area. The redirection was consistent with the intent of the Decision, which indicated that spending should be reduced in Sustainment Capital (Stations) rather than in Development Capital. This was the primary cause for the overall variance in this sub-category of $48.9 million.

Table 14: Load Customer Connection

Development Capital - Load Customer Connection			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	33.8	42.3	8.5
2017 In-service ($M)	0.2	49.1	48.9

There was an overall variances of ($1.4) million in capital expenditure and ($1.2) million to in-service additions respectively in the Risk Mitigation sub-category (Table 15). The main driver of variance was a scope reduction to the Nanticoke TS New 600V Station Service Project (D24) which resulted in a capital expenditure variance of ($0.6) million and in-service addition variance of ($0.7) million.

Table 15: Risk Mitigation

Development Capital - Risk Mitigation			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	10.9	9.5	-1.4
2017 In-service ($M)	10.3	9.1	-1.2

Variances in Facilities & Real Estate investments are largely attributed to project delivery issues associated with the Real Estate Field Facilities Capital (CC1) project where a capital expenditure variance of ($2.0) million arose due to reprioritization of additional capital enhancements which were deferred to 2018 to ensure that higher priority work in other categories could proceed and that Hydro One operated within its capital portfolio budget (Table 16).

An in-service addition variance of $1.3 million arose in respect of work being conducted on the Central Maintenance Shop oil building roof, where the project end date was pushed from 2017 to 2018 in order to address abandoned underground piping discovered during construction. Ultimately, the piping issue was resolved in 2017, allowing the project to be completed in-year and giving rise to an ISA variance of $1.3 million which largely drove the overall variance of $1.6 million in this sub-category.

Table 16: Facilities & Real Estate

Capital Common Corporate Costs and Other Costs - Facilities & Real Estate			
	DRO Forecast	**Actuals**	**Variance**
2017 Capex ($M)	9.1	6.7	-2.3
2017 In-service ($M)	5.7	7.3	1.6

6.5 2017 VARIANCES AT THE PROJECT AND PROGRAM LEVEL

Tables 17 and 18 below includes a list of all projects and programs with a total budgeted cost of greater than $3 million with planned or actual in-service additions in 2017 and shows "the status of each project and an explanation of any variances regarding scope, cost or schedule".[18] The Investment Summary Document number ("ISD") associated with each project or program is included along with a description of the project, the variance between actual and DRO forecasts for capital expenditures and in-service additions, and the status of each project compared to the time of filing. Where the project or program experienced a material variance, a variance explanation is included in the far right column using the definitions provided in section 3.2 above. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria:

- Scope Variances – For programs, material scope variances arise if the unit accomplishment filed in the rate application varied from the actual unit accomplishment. For projects, material scope variances arise if the project required internal approval for a scope change.
- Cost Variances – Material cost variances were identified where the in-year variance in cost is greater than or equal to $500,000 and the cost is 10% over budget.
- Date Variances – Material date variances were identified where the actual or projected in-service year changed from the year proposed.

Capital projects and programs that met at least one of these criteria was deemed a material variance for the purposes of this Report.

[18] Decision at p. 31

Table 17: Programs with Applicable Variance Explanations

ISD	Description	2017 Capital Expenditures ($ Millions) Approved	Actuals	Variance	2017 In Service Capital Additions ($ Millions) Approved	Actuals	Variance	Reportable Unit	Units Approved	Actuals	Variance	Variance Explanations
Transmission Stations												
Tx Transformers Demand and Spares												
Other	Tx Transformers Demand and Spares	4.2	2.4	(1.8)	3.7	2.1	(1.5)	NA	NA	NA	NA	Emergent Needs
S52	Minor Demand Capital	4.6	5.7	1.1	4.7	5.0	0.3	NA	NA	NA	NA	No material variance
S53	Spare Transformer Purchase	10.0	6.5	(3.6)	11.2	7.9	(3.3)	Number of Transformers	5	2	-60%	Emergent Needs
Site Facilities and Infrastructure												
S61	Station Building Infrastructure	12.0	10.8	(1.2)	11.2	9.4	(1.8)	NA	NA	NA	NA	Preliminary Project Definition
Transmission Lines												
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects												
S75	Wood Pole Replacements	38.8	41.2	2.4	49.4	53.5	4.0	Number of Structures	935	966	3%	Preliminary Project Definition
S76	Steel Structure Coating	39.0	42.1	3.1	30.8	31.5	0.7	Number of Structures	1,145	725	-37%	Emergent Needs
S77	Steel Structure Foundation Refurbishments	6.6	7.5	0.9	7.2	7.2	(0.0)	Number of structures	590	525	-11%	Emergent Needs
S78	Shieldwire Replacements	4.8	5.4	0.7	5.3	5.6	0.3	Number of KM of shieldwire replaced	105	105	0%	No material variance
S79	Critical Insulator Replacements	55.1	49.8	(5.3)	49.4	46.6	(2.8)	Number of Circuit Structures	3,190	3,456	8%	Project Delivery Issues
S80	Transmission Lines Emergency Restoration	7.6	8.3	0.7	8.0	8.0	(0.1)	NA	NA	NA	NA	No material variance
Transport and Work & Service Equipment												
CC2	Transport & Work Equipment	14.5	13.9	(0.6)	14.3	13.9	(0.4)	NA	NA	NA	NA	No material variance
CC3	Service Equipment	3.0	2.9	(0.1)	3.3	2.9	(0.4)	NA	NA	NA	NA	No material variance
Information Technology (including Cornerstone)												
IT1	Hardware/Software Refresh and Maintenance	6.7	6.2	(0.5)	4.5	4.5	(0.0)	NA	NA	NA	NA	No material variance

Table 18: Projects with Applicable Variance Explanations

ISD	Project Description	2017 Capital Expenditures ($ Millions) DRO Forecast	Actuals	Variance	2017 In Service Capital Additions 2017 ($ Millions) DRO Forecast	Actuals	Variance	Project Status: DRO Forecast In Service Date	DRO Forecast Status	Actual/ Bridge In Service Date	Status	Variance (in Quarters)	Variance Explanations
Transmission Stations													
Power Transformers													
Other	Power Transformer Replacements - Lakehead TS T7 & T8	1.1	1.3	0.2	9.7	9.9	0.2	Q3 2017	Execution	Q3 2017	Execution	-	No material variance
Other	Power Transformer Replacements - Dymond TS T3 & T4	2.8	2.4	(0.4)	3.3	2.6	(0.6)	Q4 2017	Execution	Q4 2017	Execution	-	Project Delivery Issues
Other	Power Transformer Replacements - Kirkland TS T12 & T13	4.6	2.9	(1.7)	8.9	7.1	(1.8)	Q4 2017	Execution	Q4 2017	Execution	-	Project Delivery Issues
Integrated Station Investment													
Other	Hinchinbrooke SS BULK	2.7	2.5	(0.2)	11.7	14.5	2.7	Q4 2018	Execution	Q4 2018	Execution	-	Preliminary Project Definition
Other	Stewartville TS – ISCR	5.6	5.4	(0.2)	6.6	4.0	(2.6)	Q3 2019	Execution	Q3 2019	Execution	-	Project Delivery Issues
Other	Sidney TS – ISCR	1.8	1.5	(0.3)	5.7	3.3	(2.4)	Q4 2017	Execution	Q2 2018	Execution	2	Project Delivery Issues
Other	Lauzon TS T5/T6; PCT & Component Replacement	3.0	3.2	0.2	4.7	4.9	0.2	Q4 2017	Execution	Q2 2018	Execution	2	Project Delivery Issues
Other	OverBrook TS, EOL Transformer Asset Rep	9.3	9.5	0.3	29.0	29.3	0.3	Q4 2017	Execution	Q4 2017	Execution	-	No material variance
Other	Scarboro TS ISCR	5.6	4.1	(1.4)	15.1	13.6	(1.4)	Q4 2017	Execution	Q4 2017	Execution	-	No material variance
Other	Integrated DESN Replacement - Goderich TS	2.1	2.3	0.2	13.6	13.8	0.2	Q2 2017	Execution	Q4 2017	Execution	2	Project Delivery Issues
Other	Nepean TS T3/T4	0.6	0.6	(0.0)	7.3	7.2	(0.1)	Q1 2017	Execution	Q1 2017	Execution	-	N/A
Other	CMS Station Service and Yard Supply Repl	7.9	6.9	(1.0)	8.3	7.1	(1.2)	Q4 2017	Execution	Q4 2017	Execution	-	Project Delivery Issues
Other	Richview TS T5/T6; Component Replacement	1.4	1.5	0.2	4.0	4.1	0.2	Q4 2017	Execution	Q4 2017	Execution	-	No material variance
S02	Air Blast Circuit Breaker Replacement - Beck #2 TS	20.9	22.7	1.8	18.9	17.8	(1.1)	Q4 2021	Execution	Q4 2022	Execution	4	Project Delivery Issues
S03	Air Blast Circuit Breaker Replacement - Bruce A TS	15.6	17.3	1.6	4.5	4.8	0.3	Q4 2019	Execution	Q4 2020	Execution	4	Project Delivery Issues

ISD	Project Description	2017 Capital Expenditures ($ Millions) DRO Forecast	Actuals	Variance	2017 In Service Capital Additions 2017 ($ Millions) DRO Forecast	Actuals	Variance	Project Status DRO Forecast In Service Date	DRO Forecast Status	Actual/ Bridge In Service Date	Status	Variance (in Quarters)	Variance Explanations
S07	Air Blast Circuit Breaker Replacement - Richview TS	11.7	14.0	2.3	26.7	26.5	(0.2)	Q4 2019	Execution	Q4 2019	Execution	-	No material variance
S08	Integrated Station Component Replacements - Beach TS	15.5	16.4	0.9	20.2	20.1	(0.1)	Q4 2019	Execution	Q4 2019	Execution	-	No material variance
S12	Integrated DESN Replacement - Espanola TS	3.1	3.3	0.3	3.5	3.8	0.3	Q2 2017	Execution	Q2 2017	Execution	-	No material variance
S19	Integrated Station Component Replacements - Allanburg TS	10.6	8.6	(2.0)	11.6	8.4	(3.2)	Q4 2018	Execution	Q4 2018	Execution	-	Accelerated Investments
S20	Integrated DESN Investments - Aylmer TS	2.3	2.3	0.0	22.3	22.4	0.0	Q2 2017	Complete	Q2 2017	Complete	-	No material variance
S21	Station Re-Investment - Barrett Chute SS	11.4	12.1	0.7	3.1	3.6	0.5	Q4 2018	Execution	Q4 2018	Execution	-	Project Delivery Issues
S22	Station Re-Investment - Birch TS	14.0	15.1	1.1	4.9	5.6	0.7	Q3 2019	Execution	Q3 2019	Execution	-	Accelerated Investments
S25	Buchanan TS BULK	6.4	5.5	(0.9)	12.8	11.5	(1.3)	Q4 2017	Execution	Q4 2017	Execution	-	Preliminary Project Definition
S28	Station Re-Investment - Crawford TS	5.7	5.2	(0.6)	10.1	9.0	(1.0)	Q4 2017	Execution	Q4 2017	Execution	-	Project Delivery Issues
S29	Station Re-Investment - DeCew Falls SS	3.7	3.7	0.0	13.8	13.8	0.0	Q2 2017	Execution	Q2 2017	Execution	-	No material variance
S32	Station Re-Investment - Frontenac TS	3.6	3.5	(0.1)	3.9	4.0	0.2	Q2 2018	Execution	Q2 2018	Execution	-	No material variance
S33	Station Re-Investment - Hanmer TS	17.7	19.5	1.8	29.4	30.2	0.8	Q3 2019	Execution	Q2 2020	Execution	3	Preliminary Project Definition
S34	Integrated Station Component Replacements - Hawthorne TS	7.3	7.9	0.6	4.8	5.9	1.1	Q4 2019	Execution	Q4 2019	Execution	-	Project Delivery Issues
S36	Station Re-Investment - Leaside TS	12.1	14.1	1.9	23.4	20.8	(2.5)	Q4 2019	Execution	Q4 2019	Execution	-	Preliminary Project Definition
S40	Station Re-Investment - Martindale TS	18.1	19.3	1.2	21.1	20.8	(0.3)	Q4 2021	Execution	Q4 2021	Execution	-	No material variance
S43	Integrated DESN Replacement – National Research Council TS	8.3	7.6	(0.8)	26.3	0.0	(26.3)	Q2 2018	Execution	Q2 2019	Execution	4	Project Delivery Issues
S45	Richview TS	6.3	7.3	1.0	14.9	20.2	5.3	Q2 2018	Execution	Q2 2018	Execution	-	Accelerated Investments
S47	Station Re-Investment - St. Isidore TS	9.5	8.9	(0.7)	27.8	0.0	(27.8)	Q4 2017	Execution	Q2 2018	Execution	2	Project Delivery Issues

ISD		Project Description	2017 Capital Expenditures ($ Millions)			2017 In Service Capital Additions 2017 ($ Millions)			Project Status					
			DRO Forecast	Actuals	Variance	DRO Forecast	Actuals	Variance	DRO Forecast In Service Date	DRO Forecast Status	Actual/ Bridge In Service Date	Status	Variance (in Quarters)	Variance Explanations
	S50	Integrated DESN Investments - Strathroy TS	5.9	6.1	0.2	10.4	18.1	7.7	Q4 2017	Execution	Q4 2017	Execution	-	Emergent Needs
Transmission Lines														
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects														
	Other	H24C - Line Refurbishment	4.2	3.9	(0.2)	9.3	9.1	(0.2)	Q3 2017	Execution	Q3 2017	Execution	-	No material variance
	S62	Line Refurbishment - C22J/C24Z/C21J/C23Z	12.5	8.4	(4.1)	18.6	14.5	(4.1)	Q4 2017	Execution	Q4 2017	Execution	-	Preliminary Project Definition
	S63	Line Refurbishment - D2L - Dymond TS x Upper Notch Jct and Martin River Jct x Crystal Falls SS	9.8	10.5	0.7	14.4	16.4	2.0	Q4 2018	Execution	Q4 2018	Execution	-	Project Delivery Issues
Inter Area Network Transfer Capability														
	D01	Clarington TS: Build new 500/230kV Station	29.9	29.7	(0.1)	0.0	15.2	15.2	Q2 2018	Execution	Q2 2018	Execution	-	Accelerated Investments
Local Area Supply Adequacy														
	D06	M20/21D Install 230 kV In-Line Switches	2.5	2.5	0.1	4.3	4.4	0.1	Q4 2017	Execution	Q4 2017	Execution	-	No material variance
	D07	York Region – Increase Transmission Capability for B82V/B83V Circuits	19.2	19.5	0.4	34.2	34.5	0.3	Q4 2017	Execution	Q4 2017	Execution	-	No material variance
	D08	Hawthorne TS: Replace two existing Transformers	10.5	10.7	0.2	7.5	7.5	0.0	Q2 2020	Execution	Q2 2021	Execution	4	Project Delivery Issues
	Other	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	0.8	0.7	(0.0)	5.4	5.4	(0.0)	Q1 2017	Execution	Q1 2017	Execution	-	No material variance
Load Customer Connection														
-	D14	Supply to Essex County Transmission Reinforcement	31.9	38.3	6.5	0.0	43.7	43.7	Q4 2018	Execution	Q4 2018	Execution	-	Accelerated Investments
Risk Mitigation														
	D24	Nanticoke TS New 600V Station Service S	6.9	6.3	(0.6)	7.3	6.6	(0.7)	Q4 2017	Execution	Q3 2018	Execution	3	Preliminary Project Definition
Information Technology (including Cornerstone)														
Information Technology (including Cornerstone)	IT3	Work Management & Mobility	4.5	4.2	(0.3)	19.5	19.4	(0.1)	Q3 2017	Complete	Q2 2017	Complete	(1)	No material variance
Facilities & Real Estate														

ISD		Project Description	2017 Capital Expenditures ($ Millions)			2017 In Service Capital Additions 2017 ($ Millions)			Project Status					
			DRO Forecast	Actuals	Variance	DRO Forecast	Actuals	Variance	DRO Forecast In Service Date	DRO Forecast Status	Actual/ Bridge In Service Date	Status	Variance (in Quarters)	Variance Explanations
Facilities & Real Estate	CC1	Real Estate Field Facilities Capital	7.0	5.0	(2.0)	3.3	4.6	1.3	Q4 2020	Planning	Q4 2020	Execution	-	Project Delivery Issues

6.6 2018 CAPITAL EXPENDITURE AND IN-SERVICE ADDITION VARIANCES AT THE ENVELOPE LEVEL

On an envelope basis in 2018, Hydro One's performance was in-line with the OEB's direction in EB-2016-0160. The net variance between Draft Rate Order ("DRO") and Actual capital expenditures was ($32.7) million and the net variance between DRO and Actual in-service additions was ($18.0) million. Table 19, below, shows 2018 variances at the envelope level. Some variances exist at the category, sub-category and project and program levels and these are explained in this report.

Table 19: Capital Expenditures and In-Service Addition Variances 2018 ($ millions)

Capital Expenditures 2018				In-Service Additions 2018		
Actuals	DRO	Variance		Actuals	DRO	Variance
967.3	1,000.0	-3%		1,160.4	1,178.4	-2%

On a net basis, the following categories in 2018 drive a positive In-Service Addition variance: $28 million variance owing to accelerated investments, and a $56 million variance owing to emergent needs Offsetting negative variances of $49 million owing to preliminary project definition and $65 million owing to project delivery issues also occurred. Looking at the overall portfolio of projects, below is a summary of the largest positive and negative variances for the year.

In 2018, the largest negative variances arose from advanced investment and delivery issues on two projects in both the Development and Sustaining Capital category: (i) D14 – Supply to Essex County Transmission Reinforcement at Leamington Transmission Station as described above; and (ii) S83 - High Voltage Underground Cable line replacement (H7L/H11L) where failure of a companion cable delayed the outage required to proceed with the project work for in-servicing $35.3 million of the project. The negative variances were then largely offset by investments mentioned above, notably (i) S47 - St. Isidore Transmission Station reinvestment; and (ii) S43 – National Research Council ("NRC") Transmission Station integrated DESN replacement.

Notable variances in the remaining categories included the following: For emergent needs, at Kenilworth Transformer Station, one transformer was in degrading condition and required immediate replacement, adding in-service capital of $9.6 million. Another important factor that contributed to emergent needs included the fire incidents that occurred at Finch transformer station and Minden transformer station, where immediate work was required to replace the damaged transformers and other auxiliaries. For preliminary project definition, the largest contributor to the negative variance ($16.2 million) was derived from Facilities Accommodation Improvements, where changes in priorities resulted in deferrals of work into 2019.

6.7 2018 CAPITAL EXPENDITURE AND IN-SERVICE ADDITION VARIANCES AT THE CATEGORY AND SUB-CATEGORY LEVEL

Table 5 below shows Hydro One's performance at the sub-category level, or "the performance at the program level (i.e. sub-category level) in terms of overall expenditures and in-service additions compared to the approved plan". [19]

[19] Decision at p. 31

1 **Table 20: 2018 Variances at the Sub-category Level**

	Capital Expenditures		Actual:DRO	In-Service Additions		Actual:DRO
	DRO	Actuals	($M)	DRO	Actuals	($M)
Sustaining Capital						
Transmission Stations						
Circuit Breakers	3.0	0.1	-2.9	7.1	0.0	-7.1
Power Transformers	0.5	-0.7	-1.2	4.5	1.7	-2.8
Other Power Equipment	0.2	0.3	0.1	3.3	0.2	-3.2
Ancillary Systems	0.5	0.7	0.2	3.7	5.3	1.6
Station Environment	0.0	0.0	0.0	0.0	0.0	0.0
Integrated Station Investments	397.4	410.7	13.3	387.3	519.3	132.0
TX Transformers Demand and Spares	67.2	82.6	15.4	70.4	79.7	9.4
Protection and Automation	58.1	44.4	-13.7	73.6	51.4	-22.2
Site Facilities and Infrastructure	10.6	16.7	6.1	9.8	17.5	7.6
Total Transmission Stations Capital	537.5	554.9	17.4	559.7	675.0	115.4
Transmission Lines						
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects	227.8	225.6	-2.2	177.3	195.8	18.5
Underground Cables Refurbishment and Replacement	30.1	16.5	-13.6	36.5	2.4	-34.1
Total Transmission Lines Capital	257.9	242.1	-15.8	213.8	198.2	-15.6
Total Sustaining Capital	795.4	796.9	1.5	773.5	873.2	99.7

Development Capital						
Inter Area Network Transfer Capability	39.0	48.9	9.9	228.0	205.3	-22.7
Local Area Supply Adequacy	28.0	20.7	-7.3	10.3	10.1	-0.2
Load Customer Connection	18.1	28.5	10.4	62.8	8.6	-54.2
Generator Customer Connection	1.2	0.3	-0.9	0.6	-0.8	-1.3
P&C Enablement for Distributed Generation	0.0	0.5	0.5	0.5	0.5	0.0
Risk Mitigation	4.3	2.6	-1.7	3.7	0.7	-3.1
Power Quality	4.1	1.4	-2.7	2.6	1.8	-0.8
TS Upgrades to Facilities Distribution Generation	0.0	0.0	0.0	0.0	0.0	0.0
Performance Enhancement	0.3	0.0	-0.2	0.2	0.0	-0.2
Smart Grid	0.0	0.2	0.2	0.0	0.2	0.2
Total Development Capital	94.9	103.1	8.2	308.7	226.4	-82.3
Operations Capital						
Grid Operating and Control Facilities	29.1	3.8	-25.3	5.3	7.0	1.7
Operating Infrastructure	13.8	5.8	-7.9	9.1	3.9	-5.3
Total Operations Capital	42.9	9.6	-33.3	14.5	10.9	-3.5
Capital Common Corporate Costs and Other Costs						
Transport and Work, and Service Equipment	16.6	9.3	-7.3	16.5	9.3	-7.1
Information Technology (including Cornerstone)	28.9	42.0	13.1	40.5	35.1	-5.3
Facilities & Real Estate	21.3	7.0	-14.4	24.8	5.4	-19.4
Other (including CDM)	0.0	-0.7	-0.7	0.0		0.0
Total Capital Common Corporate Costs and Other Costs	66.8	57.6	-9.2	81.7	49.8	-31.9
Total Transmission Capital	1,000.0	967.3	-32.7	1,178.4	1,160.4	-18.0

6.8 2018 KEY VARIANCE DRIVERS

This section describes the main drivers of variance at the sub-category level where:

- The sub-category contains a project or program that meet the OEB criteria for inclusion in this report and has a material variance;[20] or
- There is a variance of more than +/- $3.0 million at the sub-category level, even if there are no projects or programs within the sub-category with material variances.

The projects or programs that drive the variance at the sub-category level are identified and the reasons for the variance are explained. Further detail on projects and programs with a total budgeted cost of greater than $3 million with planned or actual in-service additions in 2018 are included in section 4.3 below. This information included in section 4.2 is in addition to what the OEB requested in EB-2016-0160 and is provided to give a clear picture of what drives variances during the execution of the capital program.

Table 21: Circuit Breakers

Sustaining Capital - Transmission Stations – Circuit Breakers			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	3.0	0.1	-2.9
2018 In-service ($M)	7.1	0.0	-7.1

The majority of circuit breaker investment (Table 21) is derived from the Multi-site SACE Breaker Replacement program. With imminent emergency failures from Slater

[20] A "material variance" includes scope, cost or date variances that surpass the thresholds set out in section 4.3 below and for which Hydro One has provided a variance explanation at the project or program level

and Merivale transformer stations (caused by the tornado), internal resources had shifted their priorities to addressing those concerns. This has primarily caused a delay to in-servicing capital for this program and the reduced capital expenditure.

Table 22: Other Power Equipment

Sustaining Capital - Transmission Stations - Other Power Equipment			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	0.2	0.3	0.1
2018 In-service ($M)	3.3	0.2	-3.2

The primary variance (Table 22) was derived from the Multi-Year Stations-Switch Replacement Program where it originally had a budget of $2.3M (which encompasses majority of the $3.2M variance). The program was reprioritized due to outage cancellations.

Table 23: Integrated Station Investments

Sustaining Capital - Transmission Stations - Integrated Station Investments			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	397.4	410.7	13.3
2018 In-service ($M)	387.3	519.3	132.0

For Integrated Station Investments (Table 23), the major cause of the surplus in variance is due to:

1) S47 - St. Isidore Transmission Station re-investment which experienced delays that deferred the in-service capital from 2017 to 2018, causing an additional $25.7 million in 2018.

2) S43 – National Research Council ("NRC") Transmission Station integrated DESN replacement where delays caused changes to the project schedule for in-servicing capital resulting in an additional $23.8 million in 2018.

3) An additional $20.7 million from S42 - Mohawk TS and $19.7 million from S16 - Station Re-Investment - Palmerston TS of in-service capital derived from opportunities that arose from resource and outage availability for these projects.

Table 24: Tx Transformers Demand and Spares

Sustaining Capital - Transmission Stations - TX Transformers Demand and Spares			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	67.2	82.6	15.4
2018 In-service ($M)	70.4	79.7	9.4

For Tx Transformers Demand and Spares (Table 24), Demand Capital – Equipment Failure and S53 - Purchase of Spare Transformers programs contribute to the variance for this category. With the fire incident that occurred at Finch transformer station and Minden transformer station, immediate work was required to replace the damaged transformers which created unexpected changes to the planned forecast.

Table 25: Protection and Automation

Sustaining Capital - Transmission Stations - Protection and Automation			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	58.1	44.4	-13.7
2018 In-service ($M)	73.6	51.4	-22.2

For Protection and Automation (Table 25), the negative variance is primarily driven by project delivery issues where; 1) PSIT Cyber Equipment EOL experienced a reduction of in-service capital of $7.8M - as another project took priority thus causing delays; 2) Transient Device: Full solution was anticipated in September 2018, but was not finalized until Q1 2019 thus delaying implementation; and 3) CIP-014 Physical Security

Implementation where there was a re-evaluation of scope against requirements and cost, shifting the execution to January 2019.

Table 26: Site Facilities and Infrastructure

Sustaining Capital - Transmission Stations - Site Facilities and Infrastructure			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	10.6	16.7	6.1
2018 In-service ($M)	9.8	17.5	7.6

A reprioritized investment took place to address deteriorated roofing systems at various transmission station locations (Table 26). This served as an emergent need of an additional $9.5M, which represents the bulk of this variance.

Table 27: Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects

Sustaining Capital - Transmission Lines - Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	227.8	225.6	-2.2
2018 In-service ($M)	177.3	195.8	18.5

Overhead lines refurbishment projects (Table 27) that contributed to this variance were S65 - Line Refurbishment - N21W/N22W for $10.1M and S67 - Line Refurbishment - D2L - Upper Notch Jct x Martin River Jct for $8.3M. These variances arose from opportunies for partial in-servicing of work and advancement of one segment of line work to mitigate interest expenses.

Table 28: Underground Cable Refurbishment and Replacement

Sustaining Capital - Transmission Lines - Underground Cables Refurbishment and Replacement			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	30.1	16.5	-13.6
2018 In-service ($M)	36.5	2.4	-34.1

The Underground Cable Refurbishment sub-category (Table 28) was underachieved due to S83 - H7L/H11L Cable Replacement where a failure of a companion cable delayed the outage required to proceed with the work, shifting $35.3M (which is majority of the $34.1M in this category) of in-service capital from 2018 to 2019.

Table 29: Inter Area Network Transfer Capability

Development Capital - Inter Area Network Transfer Capability			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	39.0	60.1	21.2
2018 In-service ($M)	228.0	205.3	-22.7

The majority of the variance in the Inter Area Network Transfer Capability sub-category (Table 29) was derived from Clarington TS, where a major negative variance included $15.2 million of line work that was capitalized ahead of plan in 2017 and a reduction of $7.8 million due to skywire effort that was lower than estimated, instrument transformer relocation work that was postponed until 2019 due to outage constraints, and project risks did not materialize, for a variance total of $23.0M.

Table 30: Local Area Supply Adequacy

Development Capital - Local Area Supply Adequacy			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	28.0	20.7	-7.3
2018 In-service ($M)	10.3	10.1	-0.2

Variances in the Local Area Supply Adequacy sub-category (Table 30) are primarily derived from multiple minor variances, including Guelph Area Transmission Refurbishment, where as per amendment to the environmental compliance approval (ECA), a full replacement of the spill containment systems for two transformers was not required. An interim, much cheaper, solution was implemented by installation of a drainage pipe from the old transformer pits to the new oil water separator. This was partially offset by Grainger Junction, where additional work was required to gain site access, site cleanup and associated engineering work.

Table 31: Load Customer Connection

Development Capital - Load Customer Connection			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	18.1	28.5	10.4
2018 In-service ($M)	62.8	8.6	-54.2

For Load Customer Connection (Table 31), D14 – Supply to Essex County Transmission Reinforcement at Leamington Transmission Station was accelerated to address the imminent failure of a critical transformer at Kingsville Transmission Station and was advanced late in December 2017, impacting the 2018 budget difference of $44.4M. Furthermore, an equipment failure for the Copeland MTS project shifted $3.7M of in-service capital to 2019.

Table 32: Risk Mitigation

Development Capital - Risk Mitigation			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	4.3	2.6	-1.7
2018 In-service ($M)	3.7	0.7	-3.1

In terms of Risk Mitigation (Table 32), Manby TS 115kV Load Rejection Scheme Project was delayed due to scope changes from the System Operator & LDC, shifting the in-service capital of $3.6M, which is one of the significant projects impacting the $3.1M variance noted above, to 2019.

Table 33: Grid Operating and Control Facilities

Operations Capital - Grid Operating and Control Facilities			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	29.1	3.8	-25.3
2018 In-service ($M)	5.3	7.0	1.7

Primarily in Grid Operating and Control Facilities (Table 33), OGCC Data Centre Remediation had an opportunity to partial in-service work of $3.9M, which was offset by Operating Hardware Refresh of negative $2.8M in-service due to reallocation of work to other associated projects.

Table 34: Operating Infrastructure

Operations Capital - Operating Infrastructure			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	13.8	5.8	-7.9
2018 In-service ($M)	9.1	3.9	-5.3

The overall negative variance of $5.3M for Operating Infrastructure (Table 34) was made up of numerous minor variances of approximately $1-2M each, notably; 1) Magnetometer ($1.2M) where vaults were ordered to place magnetometers but caused disturbance in other measurements, resulting in another set of vault orders; 2) Hub site End of Life and Capacity Expansion ($1.6M), where work was anticipated but priorities were shifted to other programs due to resource allocation needs; and 3) Non-Operational Data Management, where delays were due to the inability to secure resources in 2018 due to other competing business priorities.

Table 35: Transport and Work, and Service Equipment

Capital Common Corporate Costs and Other Costs - Transport and Work, and Service Equipment			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	13.8	5.8	-7.9
2018 In-service ($M)	9.1	3.9	-5.3

The negative variance in the Transport and Work Equipment sub-category (Table 35) is primarily driven by productivity gains due to right-sizing and deferral of expenditures (fleet asset optimization and specification review).

Table 36: Information Technology (including Cornerstone)

Capital Common Corporate Costs and Other Costs - Information Technology (including Cornerstone)			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	28.9	42.0	13.1
2018 In-service ($M)	40.5	35.1	-5.3

The negative in-service addition variance within the Information Technology sub-category (Table 36) of $5.3M was largely attributable to Infra/Tech Refresh Capital which experienced a reduction of $4.6M due to a change in approach related to implementation of the Windows 10 upgrade. All applications currently in use were assessed, remediated and certified in the first phase of the project. Current plan is to migrate all Hydro One users to the new Windows 10 platform over the 2019-2020 period.

Table 37: Facilities & Real Estate

Capital Common Corporate Costs and Other Costs - Facilities & Real Estate			
	DRO	**Actuals**	**Variance**
2018 Capex ($M)	21.3	7.0	-14.4
2018 In-service ($M)	24.8	5.4	-19.4

Majority of this variance in Facilties and Real Estate (Table 37) is derived from Facilities Accommodation Improvements, where changes in priorities resulted in approval delays which caused the work to move into 2019.

6.9 2018 VARIANCES AT THE PROJECT AND PROGRAM LEVEL

Tables 38 and 39 below includes a list of all projects and programs with a total budgeted cost of greater than $3 million with planned or actual in-service additions in 2018 and shows “the status of each project and an explanation of any variances regarding scope, cost or schedule”.[21] The Investment Summary Document number (“ISD”) associated with each project or program is included along with a description of the project, the variance between actual and DRO forecasts for capital expenditures and in-service additions, and the status of each project compared to the time of filing. Where the project or program experienced a material variance, a variance explanation is included in the far right column using the definitions provided in section 3.2 above. The thresholds used by Hydro One to identify “material variances” were determined using the following criteria:

- Scope Variances – For programs, material scope variances arise if the unit accomplishment filed in the rate application varied from the actual unit

[21] Decision at p. 31

accomplishment. For projects, material scope variances arise if the project required internal approval for a scope change.

- Cost Variances – Material cost variances were identified where the in-year variance in cost is greater than or equal to $500,000 and the cost is 10% over budget.
- Date Variances – Material date variances were identified where the actual or projected in-service year changed from the year proposed.

Capital projects and programs that met at least one of these criteria was deemed a material variance for the purposes of this Report.[22]

[22] Other power equipment (Table 22) and Operating Infrastructure (Table 34) do not have specific programs or projects meeting the "material variances"

Table 38: Programs with Applicable Variance Explanations

ISD	Description	2018 Capital Expenditures ($ Millions) Approved	Actuals	Variance	2018 Capital In Service Additions ($ Millions) Approved	Actuals	Variance	Reportable Unit	Units Approved	Actuals	Variance	Variance Explanations
Sustaining Capital												
Transmission Stations												
Circuit Breakers												
Other	Circuit Breakers	3.0	0.1	(2.9)	5.2	0.0	(5.2)	Number of Breakers		-	0%	Project Delivery Issues
Tx Transformers Demand and Spares												
S51	Demand Capital – Power Transformers	8.2	2.8	(5.3)	10.7	0.9	(9.8)	Number of Transformers	4	0	100%	Preliminary Project Definition
S52	Minor Demand Capital	4.1	9.6	5.5	4.0	7.3	3.3	Number of Instrument Transformers	-	18-	100%	Emergent Needs
S53	Spare Transformer Purchase	23.2	24.5	1.3	23.0	26.4	3.3	Number of Transformers	5	13	160%	Emergent Needs
Other	Demand Capital - Equipment Failure	-	11.3	11.3	0.2	9.0	8.8	Number of Transformers	-	4	100%	Emergent Needs
Protection and Automation												
S58	PSIT Cyber Equipment EOL	5.9	0.6	(5.3)	7.8		(7.8)	N/A		-	0%	Project Delivery Issues
Site Facilities and Infrastructure												
S61	Station Building Infrastructure	10.0	16.4	6.4	7.8	17.2	9.4	N/A		-	0%	Emergent Needs
Transmission Lines												
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects												
S75	Wood Pole Replacements	33.9	35.3	1.3	33.3	33.2	(0.1)	Number of Structures	850	735	14%	No material variances
S76	Steel Structure Coating	26.2	37.7	11.5	32.6	39.9	7.4	Number of Structures	1,600	1,050	34%	Project Delivery Issues
S77	Steel Structure Foundation Refurbishments	8.3	5.8	(2.4)	7.1	5.5	(1.6)	Number of Structures	700	800	14%	Project Delivery Issues
S78a[23]	Shieldwire Replacements	4.9	0.7	(4.2)	3.0	0.0	(3.0)	Number of Kilometers	110	209	90%	Project Delivery Issues
S78b[23]	Shieldwire Replacements	4.9	8.6	3.6	7.5	11.3	3.9	Number of Kilometers	110	-	-100%	Project Delivery Issues
S79a[23]	Critical Insulator Replacements	31.6	29.7	(1.8)	35.5	27.5	(8.0)	Number of Circuits	1,850	1,998	8%	Project Delivery Issues
S79b[23]	Critical Insulator Replacements	-	0.3	0.3		0.3	0.3	Number of Circuits		-	0%	No material variances
S79c[23]	Critical Insulator Replacements	31.6	35.8	4.2	30.1	30.1	2.8	Number of Circuits	3,700	3,905	6%	No material variances
S80	Transmission Lines Emergency Restoration	8.7	9.7	0.9	10.2	10.9	0.7	Number of Work orders	-	-	0%	No material variances
Other	O/H Line Refurbishment and Component Replacement	2.0	3.4	1.3	1.4	3.4	2.0	Number of Bridges	9	10	11%	Project Delivery Issues
Other	Transmission Lines Re-Investment	5.0	3.7	(1.3)	3.9	3.5	(0.4)	N/A		-	0%	No material variances
Capital Common Corporate Costs and Other Costs												
Transport and Work & Service Equipment												

[23] Multiple line items for S78 and S79 as there are some material variances at program level

CC2	Transport and Work Equipment	14.1	7.2	(7.0)	14.3	7.2	(7.2)	N/A	677	503	26%	Preliminary Project Definition
Information Technology (including Cornerstone)												
IT1	Hardware/Software Refresh and Maintenance	7.3	4.0	(3.2)	10.2	5.1	(5.1)	N/A		-	0%	Preliminary Project Definition
IT2	MFA Servers and Storage	1.8	3.6	1.8	1.8	3.6	1.8	N/A		-	0%	Emergent Needs
Other	MFA Client Tech & Periph Refresh	1.0	3.2	2.2	1.0	3.2	2.2	N/A		-	0%	Emergent Needs
Facilities & Real Estate												
CC1	Real Estate Field Facilities Capital	19.3	5.4	(14.0)	21.1	5.3	(15.7)	N/A		-	0%	Preliminary Project Definition
Other	Station Civil Infrastructure	2.0	1.6	(0.4)	3.7	0.0	(3.7)	Number of Stations		-	0%	Project Delivery Issues

Table 39: Projects with Applicable Variance Explanations[24]

ISD	Project Description	2018 Capital Expenditures ($ Millions)			2018 Capital In Service Additions ($ Millions)				Project Status					Variance Explanations
		Approved	Actuals	Variance	Approved	Actuals	Variance		Approved In Service Date	Approved Status	Actual/ Bridge In Service Date	Status	Variance (in Quarters)	
Sustaining Capital														
Transmission Stations														
Integrated Station Investment														
S02	Air Blast Circuit Breaker Replacement - Beck #2 TS	12.0	13.7	1.8	11.0	15.5	4.5	41%	Q4-2021	Execution	Q4-2022	Execution	4	Preliminary Project Definition
S03	Air Blast Circuit Breaker Replacement - Bruce A TS	12.8	15.2	2.4	30.1	21.3	(8.7)	29%	Q2-2019	Execution	Q4-2020	Execution	6	Project Delivery Issues
S07	Air Blast Circuit Breaker Replacement - Richview TS	10.2	12.2	2.1	-	18.8	18.9	100%	Q4-2019	Execution	Q4-2020	Execution	4	Accelerated Investment
S08	Integrated Station Component Replacements - Beach TS	10.5	6.9	(3.6)	23.9	21.2	(2.7)	11%	Q4-2019	Execution	Q4-2018	Execution	(4)	Preliminary Project Definition
S09	Integrated DESN Investments - Centralia TS	5.6	9.1	3.5	26.1	28.5	2.4	9%	Q4-2018	Execution	Q4-2018	Execution		No Material Variances
S10	Integrated Station Component Replacements - Dryden TS	3.7	5.1	1.4	16.8	18.1	1.3	8%	Q4-2018	Execution	Q1-2019	Execution	1	Project Delivery Issues
S14	Station Re-Investment - Kenilworth TS	1.4	9.6	8.2	-	9.6	9.6	100%	Q4-2021	Planning	Q4-2021	Execution		Emergent Needs
S15	Station Re-Investment - London Nelson TS	9.7	12.7	3.0	25.2	26.3	1.1	4%	Q1-2019	Execution	Q4-2018	Execution	(1)	No Material Variances
S16	Station Re-Investment - Palmerston TS	12.0	10.1	(1.8)	-	19.7	19.7	100%	Q2-2019	Execution	Q2-2019	Execution		Accelerated Investments
S17	Station Re-Investment - Wanstead TS	24.0	17.2	(6.8)	29.9	25.2	(4.7)	16%	Q4-2018	Execution	Q1-2019	Execution	1	Accelerated Investments
S19	Integrated Station Component Replacements - Allanburg TS	5.7	6.1	0.4	5.4	6.7	1.3	24%	Q4-2018	Execution	Q4-2018	Complete		Project Delivery Issues
S21	Station Re-Investment - Barrett Chute SS	9.1	4.0	(5.1)	21.6	15.1	(6.5)	30%	Q4-2018	Execution	Q3-2019	Execution	3	Project Delivery Issues
S22	Station Re-Investment - Birch TS	4.8	5.9	1.1	6.2	11.5	5.3	86%	Q3-2019	Execution	Q3-2019	Execution		Accelerated Investments
S26	Station Re-Investment - Cecil TS	7.5	3.3	(4.2)	9.7	2.4	(7.3)	75%	Q2-2019	Execution	Q4-2019	Execution	2	Preliminary Project Definition
S27	Station Re-Investment - Chenaux TS	6.3	6.6	0.3	8.0	18.7	10.7	134%	Q3-2019	Execution	Q3-2019	Execution		Accelerated Investments
S30	Station Re-Investment - Dufferin TS	9.4	12.6	3.2	15.3	13.3	(1.9)	13%	Q2-2019	Execution	Q3-2020	Execution	5	Project Delivery Issues
S31	Integrated Station Component Replacements – Ear Falls TS	4.8	2.9	(1.8)	14.4	14.5	0.1	1%	Q4-2018	Execution	Q4-2019	Execution	4	Project Delivery Issues
S32	Station Re-Investment - Frontenac TS	0.6	0.7	0.1	4.3	4.1	(0.2)	5%	Q2-2018	Execution	Q1-2018	Execution	(1)	No Material Variances

[24] Approved and Actual In Service Dates in Project Status section are based on official financial completion of a project, which includes minor trailing and removal work

S33	Station Re-Investment - Hanmer TS	19.4	17.3	(2.1)	29.7	6.5	(23.2)	78%	Q3-2019	Execution	Q1-2021	Execution	6	Project Delivery Issues
S34	Integrated Station Component Replacements - Hawthorne TS	10.0	4.5	(5.5)	13.0	12.7	(0.3)	2%	Q3-2019	Execution	Q4-2020	Execution	5	Project Delivery Issues
S35	Station Re-Investment - Horning TS	9.9	14.4	4.5	36.2	40.6	4.4	12%	Q4-2018	Execution	Q4-2018	Execution		Preliminary Project Definition
S36	Station Re-Investment - Leaside TS	6.0	7.5	1.5	7.0	1.3	(5.7)	81%	Q4-2018	Execution	Q2-2021	Execution	10	Project Delivery Issues
S39	Integrated Station Component Replacements - Manby TS	10.1	4.8	(5.4)	4.0	7.3	3.3	83%	Q3-2019	Execution	Q3-2019	Execution		Accelerated Investments
S40	Station Re-Investment - Martindale TS	10.2	15.1	4.9	-	9.4	9.4	100%	Q4-2021	Execution	Q4-2021	Execution		Accelerated Investments
S42	Integrated Station Component Replacements - Mohawk TS	10.6	13.8	3.2	-	20.7	20.7	100%	Q2-2019	Execution	Q4-2018	Execution	(2)	Accelerated Investments
S43	Integrated DESN Replacement – National Research Council TS	3.0	4.8	1.7	6.4	30.1	23.8	374%	Q2-2019	Execution	Q2-2019	Execution		Project Delivery Issues
S45	Integrated Station Component Replacements - Richview TS	1.7	3.0	1.3	10.1	7.1	(2.9)	29%	Q4-2017	Execution	Q4-2018	Execution	4	Accelerated Investments
S47	Station Re-Investment - St. Isidore TS	0.7	4.5	3.8	0.7	26.4	25.7	3846%	Q4-2018	Execution	Q2-2019	Execution	2	Project Delivery Issues
S50	Integrated DESN Investments - Strathroy TS	0.3	1.1	0.8	8.3	1.6	(6.8)	81%	Q2-2018	Execution	Q4-2017	Execution	(2)	Accelerated Investments
Other	Eastern Zone Station/Yard Investments	1.2	1.0	(0.1)	9.5	1.7	(7.8)	82%	Q4-2018	Execution	Q4-2019	Execution	4	Project Delivery Issues
Other	Integrated Station Component Replacements - Stewartville TS	6.9	4.3	(2.6)	5.0	0.0	(5.0)	99%	Q3-2019	Execution	Q3-2020	Execution	4	Project Delivery Issues
Other	Central Zone Station/Yard Investments	0.0	0.6	0.5	-	3.3	3.3	100%	Q4-2017	Execution	Q4-2017	Complete		Project Delivery Issues
Other	Integrated DESN Investments - Kingsville TS	14.0	7.1	(6.9)	-	9.1	9.1	100%	Q2-2018	Planning	Q3-2019	Execution	5	Emergent Needs
Other	GTA Metalclad Switchgear Replacements	1.2	0.9	(0.3)	3.6	2.7	(0.9)	25%	Q4-2018	Execution	Q1-2019	Execution	1	Project Delivery Issues
Other	Western Zone Station/Yard Investments	1.5	1.6	0.1	3.1	3.1	(0.0)	0%	Q2-2019	Execution	Q2-2019	Execution		No Material Variances
Other	Central Zone Station/Yard Investments	-	7.7	7.7	-	6.2	6.2	100%	Q4-2018	N/A	Q4-2018	Execution		Emergent Needs
Other	Coniston TS - Capital Contribution	-	3.7	3.7	-	3.7	3.7	100%	Q4-2019	N/A	Q4-2019	Execution		Preliminary Project Definition
Other	Western Zone Station/Yard Investments	2.3	2.0	(0.3)	4.5	4.3	(0.2)	5%	Q4-2018	Execution	Q2-2019	Execution	2	Preliminary Project Definition
Other	Station Re-Investment - Tomken TS	2.0	2.6	0.6	4.6	5.5	0.9	19%	Q4-2018	Execution	Q4-2018	Execution		Project Delivery Issues
Other	Detweiler TS: AC Station Service Component	1.1	3.1	2.0	6.6	8.9	2.3	34%	Q3-2018	Execution	Q4-2018	Complete	1	Preliminary Project Definition
Tx Transformers Demand and Spares														
Other	Campbell TS: T1, T2 Transformer Replacement	9.5	8.0	(1.5)	9.5	8.1	(1.4)	15%	Q4-2018	Execution	Q4-2019	Execution	4	Emergent Needs
Other	Nanticoke TS T12 & Component Replacement	18.5	18.3	(0.2)	18.6	21.4	2.8	15%	Q4-2018	Execution	Q4-2018	Execution		Emergent Needs
Protection and Automation														
S54	Transformer Protection Replacement due to 2nd Harmonic Misoperations	4.1	3.1	(0.9)	-	3.1	3.1	100%	Q4-2020	Execution	Q4-2020	Execution		Project Delivery Issues
S57	CIP V6 Transient Cyber Assets and Removeable Media	6.0	0.7	(5.2)	7.0		(7.0)	100%	Q4-2020	Planning	Q4-2020	Planning		Project Delivery Issues
S59	CIP-014 Physical Security Implementation	5.7	2.3	(3.4)	6.2	0.9	(5.3)	86%	Q4-2018	Planning	Q1-2019	Execution	1	Preliminary Project Definition
S60	NERC CIP V6 CAPEX - Low Impact Facilities	5.5	10.9	5.5	4.8	5.3	0.5	11%	Q4-2019	Planning	Q4-2019	Planning		Accelerated Investments
Other	L3P/L4P Telecom and Protection Upgrade	2.2	1.2	(1.0)	3.0		(3.0)	100%	Q4-2018	Execution	Q4-2019	Execution	4	Project Delivery Issues
Other	Cyber Security	5.0	3.3	(1.7)	5.0		(5.0)	100%	Q2-2021	Planning	Q1-2019	Execution	(9)	Preliminary Project Definition
Other	BSPS Replacement	2.9	4.0	1.1	32.5	33.0	0.5	2%	Q4-2018	Execution	Q1-2019	Execution	1	Project Delivery Issues
Transmission Lines														
Overhead Lines Refurbishment Projects, Component Replacement Programs and Secondary Land Use Projects														
S64	Line Refurbishment - C1A/C2A/C3A	2.3	1.1	(1.2)	4.6		(4.6)	100%	Q4-2018	Execution	Q4-2019	Execution	4	Preliminary Project Definition
S65	Line Refurbishment - N21W/N22W	10.9	13.8	2.9	-	10.1	10.1	100%	Q4-2019	Planning	Q4-2019	Execution		Accelerated Investments
S67	Line Refurbishment - D2L - Upper Notch Jct x Martin River Jct	10.6	11.8	1.2	-	8.3	8.3	100%	Q3-2019	Execution	Q3-2019	Execution		Accelerated Investments
S72	Tx Line Refurbishment E1Cs	1.7	3.5	1.8	1.7	3.4	1.7	99%	Q4-2023	Planning	Q4-2020	Planning	(12)	Emergent Needs

Underground Lines Cable Refurbishment & Replacement														
S83	H7L/H11L Cable Replacement	27.5	13.7	(13.8)	35.3		(35.3)	100%	Q4-2018	Execution	Q3-2019	Execution	3	Project Delivery Issues
Development Capital														
Inter Area Network Transfer Capability														
D01	Clarington TS: Build new 500/230kV Station	21.9	14.6	(7.3)	227.2	204.2	(23.0)	10%	Q4-2018	Execution	Q3-2019	Execution	3	Accelerated Investments[25]
Local Area Supply Adequacy														
Other	Grainger Jct: Install 2x230kV Switches on V71/75P	2.6	3.1	0.6	4.2	5.1	0.9	21%	Q2-2018	Execution	Q4-2018	Complete	2	Preliminary Project Definition
Other	Guelph Area Transmission Reinforcement	1.7	0.6	(1.1)	4.1	0.9	(3.2)	78%	Q3-2018	Execution	Q3-2018	Execution		Preliminary Project Definition
Load Customer Connection														
D14	Supply to Essex County Transmission Reinforcement	9.7	2.5	(7.2)	51.6	7.1	(44.4)	86%	Q2-2018	Execution	Q2-2018	Execution		Accelerated Investments
Other	Copeland MTS: Build line connection for Toronto Hydro	1.2	0.6	(0.5)	3.7		(3.7)	100%	Q4-2018	Execution	Q2-2019	Execution	2	Project Delivery Issues
Risk Mitigation														
Other	Major Risk Mitigation	1.8	1.3	(0.6)	3.6		(3.6)	100%	Q2-2018	Execution	Q2-2019	Execution	4	Preliminary Project Definition
Operations Capital														
Grid Operating and Control Facilities														
Other	OGCC Data Cntre Remediation	2.3	0.9	(1.4)	-	3.9	3.9	100%	Q1-2018	Execution	Q4-2018	Execution	3	Preliminary Project Definition
Capital Common Corporate Costs and Other Costs														
Information Technology (including Cornerstone)														
IT3	–Work Management & Mobility	2.7	3.3	0.7	3.2	3.2	0.0	1%	Q1-2019	Planning	Q4-2019	Execution	3	Project Delivery Issues
Other	Source-to-Order Transformation Project	1.4	1.5	0.1	7.6	6.8	(0.8)	10%	Q2-2018	Execution	Q2-2018	Complete		Emergent Needs
Other	Private Cloud Data Center - Capital	-	9.2	9.2	-	3.3	3.3	100%	Q4-2019	N/A	Q4-2019	Planning		Accelerated Investments

[25] A major negative variance included Clarington TS ($15.2 million), where line work was capitalized ahead of plan in 2017, remaining $7.8 million is considered Preliminary Project Definition, where the cost of the skywire replacement was lower than estimated, instrument transformer re-location work was postponed until 2019 due to outage constraints, and certain project risks did not materialize.

COMMON ASSET ALLOCATION

1. INTRODUCTION

Hydro One consists of several business divisions. It provides customers with value for money by operating as one company and maximizing efficiencies through the centralization of the maintenance, management and purchase of Common Fixed Assets ("Shared Assets") at the corporate level.

These assets include shared land and buildings, telecommunications equipment, computer equipment, applications software, tools, and transportation and work equipment ("T&WE").

Hydro One is committed to ensuring its transmission customers are only paying for investments in transmission-related assets. Its rate application process reflects this commitment. Similar to the corporate common costs allocation methodology discussion in Exhibit F, Tab 2, Schedule 6, this Exhibit will discuss the nature of Shared Assets and the method by which Hydro One allocates the costs of these assets to the Distribution and Transmission business units for determination of its revenue requirement.

2. SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (approximately 6.5% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this Exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportion of shared assets that are allocated to Transmission and Distribution.

Table 1: Summary of Gross Fixed Assets as at June 30, 2017 ($ Millions)

Category	Transmission	Distribution	Total
Total Fixed Assets	17,271.4	11,599.1	28,870.5
Shared Assets (in Total)	718.9	1,158.8	1,877.7
Shared Asset %	**38.3%**	**61.7%**	**100.0%**

Shared assets are divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value.

Table 2: Details of Shared Net Fixed Assets as at June 30, 2017 ($ Millions)

	Gross Asset Value	Accumulated Depreciation	Net Book Value
Shared Major Assets	1040.3	578.3	462.0
Shared Minor Assets	837.4	534.1	303.3
Total Shared Assets	**1,877.7**	**1,112.4**	**765.3**

3. ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly or permanently attributable to either the Transmission or Distribution business units. From year to year, the use of these shared assets may change, depending on changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, Hydro One commissioned a study by Black & Veatch ("B&V") (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study determined that shared assets should be allocated based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

Hydro One has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate decisions: RP-2005-0020/EB-2005-0378/EB-2007-0681/EB-2009-0096/EB-2013-0416, and in the previous Transmission rate decisions: EB-2006-0501/EB2008-0272/EB-2010-0002/EB-2012-0031/EB-2014-0140/EB-2016-0160. The methodology was also used in Hydro One's latest application for Distribution Rates for 2018 to 2022 (EB-2017-0049).

The appropriate use of the common asset allocation methodology for the 2020 to 2022 test years was reviewed and confirmed by B&V in 2017, and is provided as Attachment 1 to this Exhibit.

In order to account for the impact of its other Businesses, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to its Telecom and Remotes businesses. This is mainly due to the significance of a Shared Asset known as Cornerstone, which is software that integrates work management, finance, supply chain and customer service. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this proposed application. Table 3 below shows the Hydro One Common Asset allocation as at June 30, 2017.

Table 3: Hydro One Common Asset Allocation as at June 30, 2017 ($ Millions)

Total Gross Value All Hydro One Transmission & Distribution Assets			
Transmission (Total)	**$17,271.4**	**Distribution (Total)**	**$11,599.1**
Transmission (Direct)	$16,552.5	Distribution (Direct)	$10,440.3
Transmission (Common)	$718.9	Distribution (Common)	$1,158.8

REVIEW OF SHARED ASSETS ALLOCATION (TRANSMISSION) – 2019

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

JANUARY 31, 2019

BLACK & VEATCH
Building a world of difference.

Table of Contents

I. SUMMARY

A. BACKGROUND AND PURPOSE

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report which describes our Review of Shared Assets Allocation (Transmission) – 2019. This Report describes the review that Black & Veatch performed, at the request of Hydro One, of its allocation of the costs of Shared Assets in its 2020-2022 Transmission Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is the original cost (i.e., gross book value) derived as of June 30, 2017.

In 2005, Black & Veatch recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Shared Assets between its Distribution and Transmission businesses, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). Black & Veatch's objective in allocating the Shared Assets was to ensure that the allocation was reasonable, reflected best practices and was consistent with the allocation of common corporate costs, as discussed in Black & Veatch's *Review of Allocation of Common Corporate Costs (Transmission)*- dated January 31, 2019 ("2019 Common Corporate Costs Report-Transmission").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with reports issued, as follows:

Table 1 - History of Black & Veatch's Cost Allocation Reviews for Hydro One

BLACK & VEATCH REVIEW/ASSET VALUES	HYDRO ONE FILING	BLACK & VEATCH REPORT
2006 Review 12/31/2005	2006 Distribution Rates	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review 12/31/2007	2008 Transmission Rates	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review (Distribution) 12/31/2008	2010-2011 Distribution Rates	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2009 Review (Transmission) 12/31/2008	2011-2012 Transmission Rates	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010
2011 Review (Transmission) 12/31/2010	2013-2014 Transmission Rates	*Report on Shared Assets Allocation (Transmission) 2012* dated February 1, 2012
2013 Review (Distribution) 12/31/2012	2015-2019 Distribution Rates	*Report on Shared Assets Allocation (Distribution) 2013* dated September 19, 2013
2014 Review (Transmission) 12/31/2012	2015-2016 Transmission Rates	*Report on Shared Assets Allocation (Transmission) 2013* dated March 17, 2014

2015 Review (Transmission) 6/30/2015	2017-2018 Transmission Rates	*Report on Shared Assets Allocation (Transmission) 2015* dated May 4, 2016
2016 Review (Distribution) 6/30/2015	2018-2022 Distribution Rates	*Report on Shared Assets Allocation (Distribution) 2016* dated December 21, 2016

The OEB-accepted methodology has been applied by Hydro One to its Business Plan for 2020-2022 ("BP 2020-2022") data for its 2020-2022 Transmission Rates filing. This Report describes the "Review of Shared Assets Allocation (Transmission)" that Black & Veatch performed, at Hydro One's request, of its application of the methodology to its BP 2020-2022, and presents Black & Veatch's conclusions. The shared assets and their allocation are unaffected by any of the direct assignments made in the Common Corporate Cost Model to comply with the Hydro One Accountability Act. As such the last verified and reviewed Share Asset model was utilized. This model was developed and reviewed during the Winter and Spring of 2018 and relied on original costs derived as of June 30, 2017.

In its 2020-2022 Transmission Rates filing, Hydro One has allocated 38.3% of the cost of the Shared Assets to its Transmission business and 61.7% to its Distribution business. These ratios are slightly different than the ratios used in its 2017/2018 Transmission Rates filing which allocated 42.7% to its Transmission business and 57.3% to its Distribution business. This difference is primarily due to large investments in software solely relating to the distribution business (i.e., the allocation of software went from 50% Transmission in the 2017/2018 Transmission filing to currently 37%).

In addition, Hydro One has developed transfer price charge rates for its Telecom and Remotes businesses, to be used in allocating to those businesses a portion of the total revenue requirement related to the Shared Assets (e.g., depreciation expense and return). In the past, before Cornerstone assets had been placed in service, no Shared Assets were assigned to Telecom or Remotes.

B. TYPES OF SHARED ASSETS

Hydro One provided Black & Veatch with a list of the Shared Assets, by Asset Group and Asset Subgroup, as shown in Table 2.

Table 2 – Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	■ Software ■ Buildings and Telecommunications equipment

Minor Fixed Assets ("MFA")	■ Aircraft ■ Computer Hardware ■ Office equipment ■ Service equipment- Miscellaneous ■ Service equipment- Measurement and Testing ■ Service equipment- Storage ■ Tools ■ Transportation Work Equipment ■ Transportation Work Equipment- Power equipment

If an asset was estimated to be used at least 95% in either Transmission or Distribution, the cost of that asset was removed from Shared Assets and directly assigned to that business.

C. SUMMARY OF APPROACH

Allocation of Asset Costs to Transmission and Distribution

A cost driver was assigned to each asset (i.e., a building within Major Assets), asset type (i.e., Pickup Trucks within Transportation Work Equipment) or Asset Subgroup, based on discussions with Hydro One personnel to ascertain what cost driver was most closely related to the usage of the asset or the Asset Subgroup. The cost drivers used to allocate the Shared Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services. The specific steps used for each Asset Group and Subgroup are discussed below. The amounts allocated to Transmission and Distribution are summarized in Table 3, below.

Development of Transfer Price Charge Rates for Telecom and Remotes

The transfer price charge rates represent the usage of the Shared Assets by Hydro One's Telecom and Remotes businesses. Our approach to developing the transfer price charge rates was as follows:

- The portion of each asset that should be allocated to Telecom and Remotes based on the appropriate cost driver was determined.
- The total dollar amount allocated to Telecom, representing the Shared Asset cost, was computed for each asset by multiplying the Telecom share of usage by the asset cost; these dollar amounts were summed and divided by the category total cost to determine the Telecom share for the category. The same was done for Remotes. Table 4 presents the resulting Telecom and Remotes transfer price charges.
- The percentages should be applied to each component of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return), to compute the dollar amount charged to Telecom and Remotes. The amounts charged to Telecom and Remotes should be applied to reduce the revenue requirement recovered from rate payers of the Transmission and Distribution businesses.

  For example, the study determined that Telecom uses 0.51% (Table 4) of the shared Major Assets owned by Hydro One Networks. As such, 0.51% of the revenue requirement associated with major assets is charged to Telecom. The revenue requirement calculated for HONI will include

100% of the assets, however, the other revenues received from the Hydro One Inc. subsidiaries will reduce the revenue requirement which is used to derive the tariff rates.

II. DESCRIPTION OF ASSET GROUPS

A. MAJOR ASSETS

Software

Most of the software included in Shared Assets was for Hydro One's Cornerstone project, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. These costs were allocated using cost drivers that reflect the activities supported. Infrastructure costs related to each phase were allocated based on the activities those phases support. For example, the portion of the Cornerstone project related to Human Resources was allocated based on headcount. Further, some software was directly assigned to distribution notably the customer information system.

Buildings and Telecommunications Equipment

Each asset included in Buildings and Telecommunications Shared Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- **Specific estimation for a building.** For example, Sudbury Service Centre has estimated usage of Transmission-20% and Distribution-80%.
- **Direct assignment based on type of usage**. For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014-2016 and determined that Fleet usage was Transmission- 30.41% and Distribution- 69.59%; therefore the costs for buildings used for Fleet were allocated using these percentages.

  Buildings used for Training were allocated using the cost driver Headcount.
- **Cost drivers based on proxy.** For example, Buildings used to manage both Distribution and Transmission projects are allocated using the cost driver *Program Project Costs*, developed as part of the 2018 Common Corporate Costs Report- Transmission study.

B. MINOR FIXED ASSETS

Each component of Minor Fixed Assets includes many individual items. Black & Veatch reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2014-2016.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using a cost driver based on the number of *Workstations* (51% weight to Tx) and the cost driver *Headcount* (51% weight to Tx).
- **Office equipment –** Includes office furniture and other office equipment. Allocated using the cost driver *Headcount*.
- **Service equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using *Total*

Common Costs cost driver, developed as part of the 2018 Common Corporate Costs Report-Transmission study.

- **Service equipment- Measurement and Testing** – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.
- **Service equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on spending for *Operating and Maintenance costs and Capital spending*.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.
- **Transportation & Work Equipment** – Includes primarily Vehicles. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014-2016. Except for items representing less than 1.0% of cost, the usage for all of the Transportation & Work Equipment Shared Assets were recorded on time sheets and included in the computation of the Fleet cost driver.

The results are summarized in Table 3 below.

Summary of Results

Table 3 presents the allocation of Shared Assets to Hydro One's Transmission and Distribution businesses.

Table 3 - Summary of Shared Assets Allocation

Type	Total	Transmission	Distribution	Transmission %	Distribution %
Major Assets					
Intangible-ContCap	$ 33.2	$ 30.8	$ 2.5	92.6%	7.4%
Intangibles Software	$ 658.5	$ 242.6	$ 415.9	36.8%	63.2%
Buildings and fixtur	$ 168.9	$ 84.5	$ 84.4	50.0%	50.0%
Communication equipm	$ 41.2	$ 18.7	$ 22.6	45.3%	54.7%
Computer Equip Major	$ 0.3	$ 0.2	$ 0.1	72.9%	27.1%
Computer software	$ 126.3	$ 49.2	$ 77.0	39.0%	61.0%
ComputerSoftware Maj	$ 10.8	$ 5.9	$ 5.0	54.1%	45.9%
Leasehold improvemnt	$ 0.6	$ 0.2	$ 0.4	39.9%	60.1%
Syst supervisry equp	$ 0.4	$ 0.1	$ 0.3	22.0%	78.0%
Subtotal - Major Assets	$ 1,040.3	$ 432.2	$ 608.1	41.5%	58.5%
Minor Assets					
Aircraft & Railway	$ 23.7	$ 17.2	$ 6.5	72.7%	27.3%
Comp Equip -Hardware	$ 81.2	$ 41.5	$ 39.7	51.1%	48.9%
Comp Equip -Printer	$ 3.4	$ 1.8	$ 1.7	51.1%	48.9%
Measurement & testin	$ 15.5	$ -	$ 15.5	0.0%	100.0%
Misc. service equipm	$ 4.8	$ 2.2	$ 2.6	46.2%	53.8%
Office furnitre Equp	$ 11.5	$ 5.9	$ 5.6	51.1%	48.9%
Power operated equip	$ 344.3	$ 104.7	$ 239.6	30.4%	69.6%
Stores equipment	$ 1.6	$ 0.9	$ 0.7	56.7%	43.3%
Telecom Devices	$ 9.6	$ 4.9	$ 4.7	51.1%	48.9%
Tools,shop,garag equ	$ 16.7	$ 8.8	$ 8.0	52.5%	47.5%
Transportation equip	$ 325.0	$ 98.8	$ 226.2	30.4%	69.6%
Subtotal - Minor Assets	$ 837.4	$ 286.7	$ 550.7	34.2%	65.8%
Total - All Common Assets	**$ 1,877.66**	**$ 718.88**	**$ 1,158.78**	**38.3%**	**61.7%**

Table 4 presents the Shared Assets transfer price charges for Telecom and Remotes.

Table 4 - Transfer Price Charges for Other Businesses

Asset Group	Telecom	Remotes
Major Assets	0.78%	0.62%
Minor Fixed Assets	0.51%	0.66%
Total - All Shared Assets	**0.51%**	**0.66%**

Expert Evidence Statement from Black & Veatch Canada Company

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the reports listed below ("Reports") dated January 31, 2019, prepared by Black & Veatch Canada Company ("Black & Veatch").

Reports:

- Review of Allocation of Common Corporate Costs (Transmission) – 2019
- Review of Shared Assets Allocation (Transmission) – 2019
- Review of Overhead Capitalization Rates (Transmission) – 2019

Consultant:
Black & Veatch Canada Company
50 Minthorn Boulevard, Suite 501
Markham, Ontario L3T 7X8

Black & Veatch Canada Company, through its affiliate Black and Veatch Management Consulting LLC, provides strategic, economic and management consulting specializing in energy matters, in areas such as utility cost allocation and ratemaking, economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support, and technical analysis.

Qualifications:
The lead experts on this project were:

David DesLauriers

Mr. DesLauriers is a highly experienced Director in Black & Veatch Management Consulting LLC's Rates & Regulatory Services group and specializes in regulated interstate transmission pricing and wholesale electric market policy matters. He delivers a unique blend of regulatory policy acumen and practical rate setting experience to provide highly effective and supportable ratemaking and regulatory solutions to his clients. Mr. DesLauriers has advised numerous midstream energy utilities on rates and regulatory policy for the past 27 years. His areas of expertise include: electric transmission cost of service and rate design, wholesale electric market design policy and operational topics, Federal Energy Regulatory Commission (FERC) policy matters, regulatory due diligence (M&A) and compliance with FERC regulation. His clients include RTOs/ISOs, transmission owning energy companies (regulated and non-regulated) and industry stakeholder groups involved in FERC regulatory policy. Mr. DesLauriers led the common cost allocation study conducted for Kinder Morgan Inc. in 2009-2010 timeframe and testified before FERC on common cost allocation (IS09-437). In addition, he has presented expert testimony on transmission rate related matters on several occasions in recent years before the Federal Energy Regulatory Commission.

Russell Feingold

Mr. Feingold is a Vice President and leads Black & Veatch Management Consulting LLC's Rates & Regulatory Services group and has over 42 years of experience in the utility industry, the past 39 years of which have been in the field of utility management and economic consulting. Specializing in the utility industry, he has advised and assisted utility management, and industry trade and research organizations in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. He has prepared and presented expert testimony before numerous utility regulatory bodies, including the Ontario Energy Board, and has spoken widely on issues and activities dealing with the costing, pricing, and marketing of utility services. Mr. Feingold has led cost allocation review projects for Hydro One Networks Inc. related to the allocation of common corporate service costs, for Union Gas Limited and Enbridge Gas Distribution related to their regulated and unregulated underground storage operations, and for Union Gas Limited related to its Dawn to Trafalgar gas transmission system, and its corporate shared services functions.

John Taylor

Mr. Taylor is an experienced Principal Consultant in Black & Veatch Management Consulting LLC's Rates & Regulatory Services group. During his 14 year career as a consultant to utilities Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He also has experience in asset and corporate valuation, the application of real options analysis, and various risk management techniques. Mr. Taylor has also been involved in the sale of generating assets, supporting due diligence efforts and regulatory approval processes. He has filed testimony as an expert witness on class cost of service studies and on the appropriate use of statistical analysis during audit testing. He was a significant contributor to Black & Veatch Management Consulting LLC's effort to review Hydro-One's 2015 (Transmission), 2016 (Distribution), and 2019 (Transmission) shared cost allocations.

Instructions Provided:

The instructions provided to Black & Veatch Management Consulting, LLC in preparing the Report were:

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate costs among the business units that use the functions and services. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Prepare a Report of the recommended Common Corporate Costs Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Comment on the incorporation of the requirements of the Hydro One Accountability Act ("The Act") into the Common Corporate Cost Allocation Model which required Hydro One to directly assign costs for certain executives to Shareholders. (Hydro One Accountability Act, 2018, S.O. 2018, c. 10, Sched. 1).
- Identify the functions and services included in the Common Corporate costs.
- Identify activities that are performed in order to provide the functions and

services included in the Common Corporate costs.

- Determine which Common Corporate functions can distribute cost directly, which units can have cost distributed using time studies and which units require allocations using drivers and why.
- Propose and analyze all drivers used for allocation.
- Propose, analyze and perform all time studies required.
- Distribute the annual budgeted costs for each function and service among the activities required to perform it, based on time and/or cost studies.
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Cost Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- Prepare final reports for Common Corporate Costs allocation reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be submitted in Cost of Service applications.
- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Basis of Evidence:

The basis for the evidence is set forth in the Reports themselves.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, Black & Veatch (formerly R.J. Rudden Associates) was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing Shared Services, between its Transmission and Distribution businesses and other businesses. Black & Veatch recommended the methodology, which was adopted by Hydro One and accepted by the Board in its EB- 2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by Black & Veatch and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009- 0096, EB-2010-0002, EB-2012-0031, EB-2013-0416, EB-2014-0140, EB-2016-0160, and EB-2017-0049. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:

Black & Veatch Canada Company

By David DesLauriers, Director, Black & Veatch Management Consulting LLC

Date:

January 31, 2019

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Bridge Year (2019) and Test Years (2020 to 2022)
Year Ending December 31
($ Millions)

Particulars		2019		2020		2021		2022
Electric Utility Plant								
Gross plant at cost	$	18,998.1	$	19,980.4		21,216.6	$	22,443.1
Less: accumulated depreciation	$	(6,958.7)		(7,343.6)		(7,744.4)		(8,162.2)
Net plant for rate base	$	12,039.4		12,636.8		13,472.2		14,280.9
Average net plant for rate base	$			12,338.1		13,054.5		13,876.5
Construction work in progress	$			0.0		0.0		0.0
Average net utility plant	$		$	12,338.1	$	13,054.5	$	13,876.5
Working Capital								
Cash working capital	$			24.4		26.6		27.8
Materials and Supplies Inventory	$			12.0		12.2		12.4
Total working capital	$			36.4		38.8		40.2
Total rate base	$		$	12,374.5	$	13,093.3	$	13,916.7

Witness: Joel Jodoin

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment
Historical (2015, 2016, 2017, 2018), Bridge (2019) & Test (2020-2022) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance (a)	Additions (b)	Retirements (c)	Sales (d)	Transfers In/Out (e)	Closing Balance (f)	Average (g)
Historic								
1	2015	14,805.9	652.3	(40.4)	(19.8)	0.0	15,398.1	15,102.0
2	2016	15,398.1	897.5	(13.0)	(7.5)	(0.8)	16,274.2	15,836.2
3	2017	16,274.2	864.2	(47.2)	(11.8)	(2.7)	17,076.7	16,675.5
4	2018	17,076.7	1135.6	(10.9)	(15.9)	(0.5)	18,185.0	17,630.8
Bridge								
5	2019	18,185.0	950.7	(120.1)		(17.6)	18,998.1	18,591.6
Test								
6	2020	18,998.1	1037.1	(36.1)		(18.7)	19,980.4	19,489.3
7	2021	19,980.4	1297.7	(40.6)		(21.0)	21,216.6	20,598.5
8	2022	21,216.6	1293.0	(45.8)		(20.6)	22,443.1	21,829.8

Witness: Samir Chhelavda

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2015, 2016, 2017, 2018), Bridge (2019) & Test (2020-2022) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2015	5,360.4	343.0	(40.4)	(10.9)	3.3	5,655.5	5,508.0
2	2016	5,655.5	350.8	(10.2)	(6.8)	0.1	5,989.4	5,822.4
3	2017	5,989.4	370.6	(47.2)	(11.0)	(0.2)	6,301.7	6,145.5
4	2018	6,301.7	387.3	(10.9)	(14.6)	(1.4)	6,662.1	6,481.9
Bridge								
5	2019	6,662.1	416.7	(120.1)		0.0	6,958.7	6,810.4
Test								
6	2020	6,958.7	421.0	(36.1)		0.0	7,343.6	7,151.2
7	2021	7,343.6	441.4	(40.6)		0.0	7,744.4	7,544.0
8	2022	7,744.4	463.6	(45.8)		0.0	8,162.2	7,953.3

Witness: Samir Chhelavda

FIXED ASSET CONTINUITY SCHEDULES: DX CHAPTER 2

APPENDIX 2-BA

This Exhibit has been filed in MS Excel format.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Historical (2015, 2016, 2017, 2018), Bridge (2019) & Test (2020-2022) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Capital Expenditures	Transfers To Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historic					
1	2014	739.7	814.5	(885.7)	668.4
1	2015	668.4	896.8	(677.8)	887.4
2	2016	887.4	958.4	(880.3)	965.4
3	2017	965.4	925.8	(847.1)	1,044.1
4	2018	1,044.1	955.1	(1,145.2)	854.1
Bridge					
5	2019	854.1	1,038.2	(902.6)	989.7
Test					
6	2020	989.7	1,192.2	(1,018.8)	1,163.1
7	2021	1,163.1	1,317.7	(1,275.0)	1,205.8
8	2022	1,205.8	1,369.6	(1,280.7)	1,294.7

Witness: Samir Chhelavda

WORKING CAPITAL

1. INTRODUCTION

Hydro One must be in a position financially to perform the work that keeps the system safe and reliable and provides strong transmission outcomes its customers will value. Working capital is integral to this commitment. Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study.

In 2009, Hydro One commissioned Navigant to carry out a lead-lag study. In EB-2009-0096 Decision with Reasons, the OEB accepted the results of the Navigant lead-lag study. Hydro One commissioned Navigant to conduct an updated lead-lag study for the Transmission business in June 2017. The study was based on 2016 actual results. The finalized lead-lag study is included in Exhibit C, Tab 5, Schedule 1, Attachment 1 (Working Capital Requirements of Hydro One Networks' Transmission Business).

2. SUMMARY

Hydro One Transmission's net cash working capital requirement for the 2020 test year is $24.4 million or 6.5% of OM&A ($375.8 million). Applying the same formula, the net cash working capital requirement average in years 2020 through 2022 is approximately 6.9% of OM&A.

Table 1 summarizes the net cash working capital requirements determined by using the lead-lag days from the Navigant study to reflect the 2020-2022 test year revenues, expenses and HST amounts (Table 2).

The methodology used to determine the net cash working capital required is based on the Navigant study that was accepted by the OEB and updated as part of this filing, and it takes the following into consideration:

- the most important elements of revenue lags, including the service, billing and collection lags; and
- the most important elements of expense leads such as payroll and benefits, operations, maintenance, administration expenses, and taxes, including property taxes.

Table 1: Transmission Net Cash Working Capital Requirement

(All Data in $millions Except Lead/Lag Days)

	Revenue Lag (Days)	**Expense Lead (Days)**	**Net Lag (Lead Days)**	**2020 Test Year**	**2021 Test Year**	**2022 Test Year**
	(A)	(B)	(C)	(D)	(E)	(F)
Expenses						
OM&A	35.52	26.76	8.76	375.8	381.1	386.4
Removal Costs	35.52	23.66	11.85	54.1	59.7	61.5
Environmental Costs	35.52	14.63	20.89	12.6	17.4	19.3
Interest on Long-Term Debt	35.52	8.17	27.34	316.6	335.0	356.1
Income Tax	35.52	19.77	15.75	81.1	89.9	93.2
Total				**840.3**	**883.1**	**916.5**
HST				338.1	360.3	375.9
Total Amounts Paid/Accrued				**1178.4**	**1243.4**	**1292.4**
Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: For Test Years 2020 to 2022 (Col (D)*Col (C)/365))						
OM&A				9.0	9.1	9.3
Removal Costs				1.8	1.9	2.0
Environmental Costs				0.7	1.0	1.1
Interest on Long-Term Debt				23.7	25.1	26.7
Income Tax				3.5	3.9	4.0
Total				**38.6**	**41.1**	**43.1**
HST (see Table 2)				-14.2	-14.4	-15.3
Net Working Cash Required				**24.4**	**26.6**	**27.8**

Table 2: Transmission Summary of HST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

	HST Lead Time (Days)	Working Capital Factor	2020 Test Year	2021 Test Year	2022 Test Year
Revenue (external)	(46.42)	(12.72%)	-28.1	-29.7	-31.1
OM&A	43.80	12.00%	1.9	2.0	2.0
Removal costs	43.84	12.01%	0.1	0.1	0.1
Environmental costs	43.84	12.01%	0.1	0.1	0.1
Capital expenditures	43.84	12.01%	11.8	13.1	13.6
Total			**-14.2**	**-14.4**	**-15.3**

More detail on the Transmission HST Cash Working Capital Requirement is in page 11 of Attachment 1.

3. COMPARISON TO PRIOR STUDY

A comparison of the current study to the prior Navigant study is included in attachment 1 of this exhibit starting on page 14. The study summarizes the changes and main drivers broken into revenue lag days, OM&A expenses lead days, interest expenses lead days, corporate income taxes lead days and removals and environmental remediation lead days.

The impact of implementing the current study results as compared to previously approved study has resulted in an increase in cash working capital of $6.5 million, or an increase in revenue requirement of approximately $0.49 million per year.

Working Capital Requirements of Hydro One Networks

Transmission Business

Prepared for:

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This report (the “report”) was prepared for Hydro One Networks Inc. (“HONI”) by Navigant Consulting, Ltd. (“Navigant”). The report was prepared solely for the purposes of HONI’s rate filing before the Ontario Energy Board (“OEB”) and may not be used for any other purpose. Use of this report by any third party outside of HONI’s rate filing is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report’s contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Navigant extends no warranty to any third party.

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SECTION I: EXECUTIVE SUMMARY

Summary

In preparation for an upcoming transmission rate filing before the OEB, HONI retained Navigant to prepare an update to its prior working capital study (EB-2016-0160). This report provides the results of the update and the working capital requirements of HONI's transmission business.

Listed below are key findings and conclusions from this study:

1. In terms of Revenue Lag days, the results from this study are higher by 2.72 days versus the prior study primarily driven by:
    a. Delay of payments throughout the year from the IESO resulting in an increase of 0.89 IESO Revenue lag days versus the prior study; and,
    b. A higher portion of overdue Other External Revenues, and Other External Revenues being written off after 2 years rather than 1 year, collectively resulting in an increase of 19.54 Other External Revenue Lag days.

    After dollar weighting the IESO Revenue and Other External Revenue Lag days, the total Revenue Lag days from this study is higher by 2.72 days;
2. In terms of Expense Lead days, the results from this study are generally comparable with HONI's previous transmission working capital study. Where there are differences, they have been identified, explained, and their impact on working capital requirements quantified;
3. The approach and methods used in this study are generally consistent with prior HONI transmission studies as well as studies performed by other local distribution companies in Ontario; and,
4. Data from calendar year 2016 was used as a basis for this analysis. Results from the lead-lag study applied to HONI's test years identify the following working capital amounts.

Table 1: Summary of Working Capital Requirements

Year	2020	2021	2022
Percentage of OMA	**6.49%**	**6.96%**	**7.14%**
Working Capital Requirement $(M)	**$24,389,327**	**$26,514,233**	**$27,609,605**

Organization of the Report

Section II of this report discusses the lag times associated with HONI's collections of revenues. This includes a description of the sources of revenues and how an overall revenue lag is derived.

Section III presents the lead times associated with HONI's expenses. This includes a description of the types of expenses incurred by HONI's transmission operations and how expenses are treated for the purposes of deriving an overall expense lead, including the working capital requirement associated with the Harmonized Sales Tax ("HST").

Section IV presents the working capital requirements of HONI's transmission business.

Section V presents a summary comparison of the results from this study with results from the EB-2016-0160 study. Differences between the two have been noted, explained, and their impacts on working capital quantified. The intent of presenting the discussion in Section V is to demonstrate that the approach used in this study is an accurate reflection of the current transmission operations of HONI and that the results are reasonable when compared with the prior transmission studies.

SECTION II: WORKING CAPITAL METHODOLOGY

Working capital is the amount of funds that are required to finance the day-to-day operations of a regulated utility and are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to HONI (or "lag") together with the time between which HONI receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in HONI's rate base for the purpose of deriving revenue requirement.

Key Concepts

Mid-Point Method

When a service is provided to (or by) HONI over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([\quad - X] + 1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. The formula uses the number of days in a year ("A") and the number of periods in a year ("B"):

$$\text{Mid-Point} = \frac{A/B}{2}$$

Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) HONI. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

Expense Lead Components

As used in this study, Expense Leads are defined to consist of two components:

1. Service lead component (services are assumed to be provided to HONI evenly around the mid-point of the service period), and
2. Payment lead component (the time period from the end of the service period to the time payment was made and when funds have left HONI's possession).

Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 Million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated transmission business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HONI's operations, interviews with personnel within HONI's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) HONI, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to transmission operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

SECTION III: REVENUE LAGS

A transmission utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HONI until the date payments are received from customers and funds are available to HONI.

Interviews with HONI personnel indicate that its transmission business receives funds from the following funding streams:

1. The Independent Electric System Operator ("IESO"); and,
2. Other sources including municipalities, electricity retailers, and for miscellaneous services such as jobbing and contracting work performed by HONI.

Data from HONI's billing system indicates that in 2016, payments from the IESO contributed approximately 90% of HONI's transmission revenues. The lag times associated with the funding streams above were weighted and combined to calculate an overall revenue lag time as shown below.

Table 2: Summary of Revenue Lag

Description	Lag Days	Revenues ($M)	Weighting	Weighted Lag
IESO Revenues	33.61	$1,507	90%	30.23
Other Revenues	52.65	$168	10%	5.28
Total		**$1,676**	**100%**	**35.52**

IESO Revenues

HONI receives revenues from the IESO monthly in a manner that is consistent with the settlement and payment procedures outlined in the IESO's tariff. Taking this information into account and using actual amounts and dates received for 2016, a revenue lag of 33.61 days was determined. The derivation is shown in Table 3 below.

Table 3: Summary of IESO Revenues

Period Beginning	Period Ending	Payment Date	Payment Amount	Weighting Factor	Service Lag Time	Payment Lag Time	Total Lag Time	Weighted Lag
1/1/2016	1/31/2016	2/17/2016	$123.68	8.20%	15.50	17.00	32.50	2.67
2/1/2016	2/29/2016	3/16/2016	$123.14	8.17%	14.50	16.00	30.50	2.49
3/1/2016	3/31/2016	4/18/2016	$119.55	7.93%	15.50	18.00	33.50	2.66
4/1/2016	4/30/2016	5/17/2016	$111.76	7.41%	15.00	17.00	32.00	2.37
5/1/2016	5/31/2016	6/20/2016	$121.19	8.04%	15.50	20.00	35.50	2.85
6/1/2016	6/30/2016	7/21/2016	$134.80	8.94%	15.00	21.00	36.00	3.22
7/1/2016	7/31/2016	8/19/2016	$140.74	9.34%	15.50	19.00	34.50	3.22
8/1/2016	8/31/2016	9/19/2016	$142.98	9.49%	15.50	19.00	34.50	3.27
9/1/2016	9/30/2016	10/21/2016	$141.40	9.38%	15.00	21.00	36.00	3.38
10/1/2016	10/31/2016	11/17/2016	$110.02	7.30%	15.50	17.00	32.50	2.37
11/1/2016	11/30/2016	12/16/2016	$114.28	7.58%	15.00	16.00	31.00	2.35
12/1/2016	12/31/2016	1/18/2017	$123.91	8.22%	15.50	18.00	33.50	2.75
Total			**$1,507.45**	**100.00%**				**33.61**

Other Revenues

The lag time associated with other revenues is defined as the sum of an average service lag time and a dollar-weighted payment lag time. The expectation is that HONI bills monthly for services such as merchandising, jobbing, rents and leases of HONI property. Thus, the mid-point of a month (i.e., 15.21 days) was used as indicative of the service lag time. Accounts receivable balances on other revenues for 2016 were reviewed to determine a dollar-weighted payment lag which was determined to be 37.44 days. Taken together with the assumed monthly service lag time, the lag time associated with other revenues was determined as 52.65 days.

SECTION IV: EXPENSE LEADS

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HONI's transmission business, and the lead times associated with payments for services provided to HONI. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Operating, Maintenance and Administration ("OM&A") Expenses;
2. Removal & Environmental Remediation Costs;
3. Interest on Long Term Debt;
4. Corporate Income Tax; and,
5. HST.

OM&A Expenses

For the purpose of the transmission lead-lag study, OM&A expenses were considered to consist of payments made by HONI to its vendors in the following categories:

1. Payroll and Benefits;
2. Property Taxes;
3. Corporate Procurement Card;
4. Lease Payments;
5. Payments to Inergi;
6. Consulting and Contract Staff; and,
7. Miscellaneous OM&A

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 26.76 days for OM&A expenses.

Table 4: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Payroll and Benefits	$551.69	53.18%	20.29	10.79
Property Taxes	$51.79	4.99%	-22.24	-1.11
Corporate Procurement Card	$27.84	2.68%	29.58	0.79
Lease Payments	$3.78	0.36%	-14.25	-0.05
Payments to Inergi	$61.94	5.97%	83.12	4.96
Consulting and Contract Staff	$63.14	6.09%	-0.98	-0.06
Miscellaneous OM&A	$277.27	26.73%	42.79	11.44
Total	**$1,037.45**	**100.00%**		**26.76**

Payroll and Benefits

The following items were considered to be expenses related to the payroll and benefits of HONI's transmission business:

1. Four types of payroll including Basic & Management, Construction & Trades, Board of Directors and Supervisor Pension payroll;
2. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings for each of the payroll types;
3. Contributions made by Hydro One to the Hydro One Pension Plan;
4. Union Benefits, Group Health, Dental, and Life Insurance related administrative fees and claims;
5. Payments made by Hydro One for the Employer Health Tax ("EHT"); and,
6. Payments made by Hydro One to the Worker Safety Improvement Board ("WSIB").

When all payroll, withholdings and benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 20.29 days as shown in Table 5 below.

Table 5: Summary of Payroll & Benefits Expenses

Description	Amounts ($M)	Weighting	Expense Lead Time	Weighted Lead Time
Pensions	$49.52	8.98%	19.19	1.72
WSIB	$3.51	0.64%	45.66	0.29
Employee Health Tax	$8.64	1.57%	30.56	0.48
Group Benefits	$50.51	9.16%	7.84	0.72
Payroll	$297.40	53.91%	18.84	10.16
Payroll Withholdings	$142.10	25.76%	26.88	6.92
Total	**$551.69**	**100.00%**		**20.29**

Property Taxes

HONI makes property tax payments to several municipalities and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year's property taxes and are typically made in installments. Using actual payment dates and amounts associated with HONI's transmission business for calendar year 2016, a dollar-weighted expense lead (-lag) time of -22.24 days was determined.

Corporate Procurement Card

Procurement (or charge) cards are used by the HONI's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on actual invoices from the HONI's charge card provider and payments made by HONI, a dollar-weighted expense lead time of 29.58 days was determined.

Lease Payments

HONI leases office space to support its ongoing transmission operations in several different locations. HONI presently has leases for Trinity, Atrium, Barrie, Mississauga and Mural locations. HONI generally makes its lease payments on or around the end of the month prior for the current month. Taking this information into account and using actual invoices and payments for 2016, a dollar-weighted expense lead (-lag) time of -14.25 days was determined.

Payments to Inergi

Inergi (a division of CapGemini) provides a number of services to HONI including (and not limited to) customer service operations, finance, human resources, accounts payable, information technology, IESO settlement services, and supply management services. Based on a review of payments made by HONI to Inergi in 2016, a dollar-weighted expense lead time of 83.12 days was determined.

Consulting and Contract Staff

HONI engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting.
A dollar-weighted expense lead (-lag) time of -0.98 days was determined based on a review of invoices rendered and payments made by HONI in 2016.

Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to HONI. Based on transactions in HONI's accounts payable system under this category, a dollar-weighted expense lead time of 42.79 days was derived.

Removal and Environmental Remediation Costs

HONI incurs costs when removing or replacing equipment from existing sites or right of ways. Further, costs relating to environmental remediation at these sites are also incurred. While costs are required to be reported as a depreciation and amortization expense for accounting purposes, there is a cash flow impact associated with HONI's expenditures on such removal and environmental remediation costs. Based upon discussions with HONI staff, estimates for the derivation of removal and environmental remediation costs were determined and summarized in Table 6 below.

Table 6: Summary of Removal and Environmental Remediation Expenses

Description	Expense Lead Time	% of Remediation Expenses	Weighted Lead Time
Removal			
HONI Labour	20.29	85.00%	17.25
HONI Materials	42.79	15.00%	6.42
External Labour	-0.98	0.00%	0.00
External Materials	42.79	0.00%	0.00
Total		**100.00%**	**23.66**
Environmental Remediation			
HONI Labour	20.29	42.50%	8.62
HONI Materials	42.79	7.50%	3.21
External Labour	-0.98	42.50%	-0.42
External Materials	42.79	7.50%	3.21
Total		**100.00%**	**14.63**

Interest Expense

HONI makes interest payments on its long term and short term debt. Such payments are generally made twice a year. Taking into account the various bonds and other long term debt instruments, a dollar-weighted expense lead time of 8.17 days was determined for the 2016 calendar year.

Corporate Income Tax

HONI pays corporate income tax in monthly installments to the relevant taxing authorities. Using payment amounts that were made in calendar year 2016, a dollar-weighted expense lead time of 19.77 days was determined for corporate income taxes.

Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in HONI's transmission lead-lag study.

1. IESO Revenues;
2. OM&A[2]; and,
3. Removals, Environmental Remediation and Capital Costs.

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 7. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HONI's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice.

Table 7: Summary of HST Working Capital Amounts

Description	HST Lead Time	2020 ($M)	2021 ($M)	2022 ($M)
IESO Revenues	-46.42	-$28.12	-$29.62	-$31.02
OM&A Expenses	43.80	$1.92	$1.95	$1.98
Environmental Remediation	43.84	$0.07	$0.10	$0.11
Removals	43.84	$0.10	$0.11	$0.11
Capital	43.84	$11.85	$13.13	$13.65
Total		**-$14.19**	**-$14.33**	**-$15.17**

[2] Costs within OM&A that attract HST include Corporate Procurement Card, Trinity Lease Payments, Payments to Inergi, Consulting and Contract Staff and Miscellaneous OM&A

SECTION V: HYDRO ONE TRANSMISSION – WORKING CAPITAL REQUIREMENTS

Using the results described under the discussion of revenue lags and expense leads, and applying them to HONI's proposed transmission expenses for the 2020-2022 test years, HONI's working capital requirements were determined and is shown in the tables below.

Table 8: HONI Transmission Working Capital Requirements (2020)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor*	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	35.52	26.76	8.76	2.39%	$375.92	$8.99
Corporate Income Tax	35.52	19.77	15.75	4.30%	$84.96	$3.66
Interest Expense	35.52	8.17	27.34	7.47%	$313.91	$23.45
Environmental Remediation	35.52	14.63	20.89	5.71%	$12.61	$0.72
Removals	35.52	23.66	11.85	3.24%	$54.13	$1.75
Total					**$841.52**	**$38.57**
HST						-$14.19
Total - Including HST						**$24.39**
Working Capital as a Percent of OM&A incl. Cost of Power						**6.49%**

**There is a minor difference in the working capital factors for 2020 compared to other years in the study because 2020 is leap year*

Table 9: HONI Transmission Working Capital Requirements (2021)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	35.52	26.76	8.76	2.40%	$381.18	$9.14
Corporate Income Tax	35.52	19.77	15.75	4.31%	$89.98	$3.88
Interest Expense	35.52	8.17	27.34	7.49%	$332.19	$24.89
Environmental Remediation	35.52	14.63	20.89	5.72%	$17.40	$1.00
Removals	35.52	23.66	11.85	3.25%	$59.69	$1.94
Total					**$880.45**	**$40.85**
HST						-$14.33
Total - Including HST						**$26.51**
Working Capital as a Percent of OM&A incl. Cost of Power						**6.96%**

Table 10: HONI Transmission Working Capital Requirements (2022)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	35.52	26.76	8.76	2.40%	$386.52	$9.27
Corporate Income Tax	35.52	19.77	15.75	4.31%	$91.64	$3.95
Interest Expense	35.52	8.17	27.34	7.49%	$353.12	$26.45
Environmental Remediation	35.52	14.63	20.89	5.72%	$19.26	$1.10
Removals	35.52	23.66	11.85	3.25%	$61.52	$2.00
Total					**$912.06**	**$42.78**
HST						-$15.17
Total - Including HST						**$27.61**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.14%**

SECTION VI: FINDINGS AND CONCLUSIONS

The purpose of this section is to compare the results from this study to HONI's prior working capital transmission study as per EB-2016-0160. In addition, this section demonstrates that the results from this study reflect the current operations of HONI.

Comparison with Prior Transmission Study

Table 11: HONI Transmission Working Capital Requirements (2017) – Prior 2015 Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	32.79	33.83	-1.04	-0.28%	$425.80	-$1.21
Corporate Income Tax	32.79	19.63	13.16	3.61%	$81.30	$2.93
Interest Expense	32.79	-1.33	34.12	9.35%	$276.54	$25.85
Environmental Remediation	32.79	18.29	14.50	3.97%	$11.62	$0.46
Removals	32.79	27.62	5.18	1.42%	$53.38	$0.76
Total					**$848.65**	**$28.80**
HST						-$14.13
Total - Including HST						**$14.67**
Working Capital as a Percent of OM&A incl. Cost of Power						**3.44%**

Table 12: HONI Transmission Working Capital Requirements (2020) – Current 2018 Study

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	35.52	26.76	8.76	2.39%	$375.92	$8.99
Corporate Income Tax	35.52	19.77	15.75	4.30%	$84.96	$3.66
Interest Expense	35.52	8.17	27.34	7.47%	$313.91	$23.45
Environmental Remediation	35.52	14.63	20.89	5.71%	$12.61	$0.72
Removals	35.52	23.66	11.85	3.24%	$54.13	$1.75
Total					**$841.52**	**$38.57**
HST						-$14.19
Total - Including HST						**$24.39**
Working Capital as a Percent of OM&A incl. Cost of Power						**6.49%**

Table 13: Working Capital Requirements (Current versus Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	2.72	-7.07	9.79	2.68%	-$49.87	$10.20
Corporate Income Tax	2.72	0.14	2.59	0.70%	$3.65	$0.72
Interest Expense	2.72	9.50	-6.78	-1.88%	$37.37	-$2.40
Environmental Remediation	2.72	-3.67	6.39	1.74%	$0.99	$0.26
Removals	2.72	-3.95	6.67	1.82%	$0.74	$1.00
Total						**$9.78**
HST						-$0.06
Total - Including HST						**$9.72**
Working Capital as a Percent of OM&A incl. Cost of Power						**3.04%**

Revenue Lag

As shown in Table 13 above, the overall revenue lag in the current study has increased to 35.52 versus the prior study of 32.79, a difference of 2.72 days. The drivers of this change are described below, in order of largest impact:

1. IESO revenue lag days have increased resulting from a delay in payments throughout the year from the IESO;
2. Other external revenue lag days have increased resulting from a higher percentage of overdue revenues; and,
3. Other external revenue lag days have increased resulting from bad debt write-off's occurring after 2 years versus 1 year, which was what was assumed in the prior study

Table 14 below also shows a breakdown of the revenue lag component for the current and prior study. The differences between the studies are driven by the factors above.

Table 14: Revenue Lag Comparison

Description	Current Study			Prior Study		
	Lag Days	Revenues ($M)	Weighted Lag Days	Lag Days	Revenues ($M)	Weighted Lag Days
IESO Revenues	33.61	$1,507	30.23	32.72	$1,557	26.44
Other External Revenues	52.65	$168	5.28	33.11	$370	6.35
Total		**$1,676**	**35.52**			**32.79**

OM&A Expenses

As shown in Table 13 above, the overall weighted expense lead in the current study has decreased to 26.76 versus the prior study of 33.83, a difference of 7.07 days. The drivers of this change are described below, in order of largest impact:

1. Miscellaneous OM&A expense lead days did not change significantly. However, when taken together with other OM&A expense categories, the weighted Miscellaneous OM&A lead days has decreased from 19.44 to 11.44. This is because certain cost items that belonged to this cost category in the prior study were removed in the current study, as they are now captured within other OM&A expense buckets;
2. Payments to Inergi expense lead days have increased as data regarding exact payment dates were obtained during this study whereas assumptions for payments dates were made in the prior study; and,
3. Property tax expense lead days have decreased as there are more payments for property taxes in the first half of the year than in the latter half of the year, which was not the case in the prior study.

Table 15 below also shows a breakdown of the expense lead component for the current and prior study. The changes between the studies are driven by the factors above.

Table 15: OM&A Expense Lead Comparison

Description	Current Study			Prior Study		
	Lead Days	Expenses ($M)	Weighted Lead Days	Lead Days	Expenses ($M)	Weighted Lead Days
Payroll & Benefits	20.29	$551.69	10.79	23.84	$503.21	9.72
Property Taxes	-22.24	$51.79	-1.11	23.89	$52.88	1.02
Corporate Procurement Card	29.58	$27.84	0.79	29.87	$36.96	0.89
Lease Payments	-14.25	$3.78	-0.05	-14.21	$4.02	-0.05
Payments to Inergi	83.12	$61.94	4.96	32.82	$102.51	2.73
Consulting and Contract Staff	-0.98	$63.14	-0.06	1.91	$44.90	0.07
Miscellaneous OM&A	42.79	$277.27	11.44	49.00	$489.65	19.44
Total		**$1,037.45**	**26.76**		**$1,234.14**	**33.83**

Interest Expense

Interest expense lead days have increased versus the prior study. The change is primarily driven by a higher frequency of interest payments occurring in the second half of 2016 resulting in an expense lead instead of an expense lag. Table 16 below shows a breakdown of the frequency of interest payments by month and the associated weighted lead days; as can be seen the current study has more payments occurring in the second half of 2016 resulting in the increase in expense lead days.

Table 16: Interest Expense Lead Comparison

Month	Current Study		Prior Study	
	Frequency of Payments	Weighted Lead Days	Frequency of Payments	Weighted Lead Days
January	5	-17.84	6	-17.55
February	0	0.00	3	-6.31
March	5	-7.86	3	-6.71
April	6	-10.19	6	-10.83
May	1	-2.00	6	-4.94
June	7	-3.05	2	-0.17
July	5	2.35	6	1.99
August	3	2.09	3	2.96
September	5	5.31	4	4.75
October	6	14.24	6	14.17
November	1	6.76	4	12.41
December	7	18.36	3	8.88
Total		**8.17**		**-1.33**

Corporate Income Tax

Corporate income tax expense lead days have not changed significantly in this study versus the prior study. Corporate income tax currently has an expense lead time of 19.77 days versus 19.63 days in the prior study. This indicates that there has not been a significant operational change in how corporate income tax is being treated from a working capital perspective.

Removals and Environmental Remediation

Removals and environmental remediation weighted expense lead days have both decreased by 3.67 and 3.95 days respectively in this study versus the prior study. This change is driven by lower Hydro One labour and materials lead times, and lower outside services labour and materials lead times in the current study versus the prior study. The Hydro One labour lead time is equivalent to the total weighted payroll and benefits lead time (20.29 days), the materials lead time is equivalent to the miscellaneous OM&A expense lead time (42.79 days), and the outside services labour lead time is equivalent to the consulting and contract staff lead time (-0.98 days). The differences in the lead times between the studies for removals and environmental remediation can be found in Table 15.

Comparison with Prior Transmission Study Using Constant Revenue Lag Days

The difference between the 2020 and 2017 working capital requirement from the current study versus the prior study respectively, is 3.04% (6.49% in 2020 and 3.44% in 2017 as shown in Table 18). Since the revenue lag days was one of the most significant change over the prior study, an analysis using constant revenue lag days between the two studies was conducted to show the individual impacts of the differences in expense lead days. Table 17 below shows that when holding revenue lag days constant, working capital requirement in 2020 is approximately 1.38% higher in the current study than in 2017 from the prior study, indicating that the primary drivers of the change are from revenue lag days (of the 3.04% difference between the studies, 1.38% of the difference is attributable to the change in revenue lag), and the expenses lead days (of the 3.04% difference between studies, 1.67% of the different is attributable to the change in expense leads).

Table 17: Working Capital Requirements with Revenue Lag Days Held Constant (Current VS Prior)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirements ($M)
OM&A Expenses	0.00	-7.07	7.07	1.93%	-$49.87	$7.40
Corporate Income Tax	0.00	0.14	-0.14	-0.05%	$3.65	$0.09
Interest Expense	0.00	9.50	-9.50	-2.62%	$37.37	-$4.74
Environmental Remediation	0.00	-3.67	3.67	0.99%	$0.99	$0.16
Removals	0.00	-3.95	3.95	1.08%	$0.74	$0.59
Total						**$3.52**
HST						-$0.06
Total - Including HST						**$3.46**
Working Capital as a Percent of OM&A incl. Cost of Power						**1.38%**

Conclusion

The results of this study indicate a higher working capital requirement compared to HONI's EB-2016-0160 transmission lead-lag study. Table 18 below summarizes the working capital requirements calculated in this study along with historical working capital amounts.

Table 18: Summary of Historical Working Capital Requirements

	2012 Study		2014 Study		2016 Study		2018 Study	
Test Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2020**	**2021**
WCR as a % of OM&A	**2.80%**	**2.58%**	**2.81%**	**2.27%**	**3.44%**	**3.69%**	**6.49%**	**6.96%**

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the report "Working Capital Requirements of Hydro One Networks Transmission Business – 2019 to 2023" ("Report") for Hydro One Transmission's upcoming transmission revenue requirement application, prepared by Navigant Consulting, Ltd. ("Expert").

Consultants:

Name	**Benjamin Grunfeld** Managing Director	**Craig Sabine** Director	**Andy Tam** Associate Director	**Jodi Amy** Associate Director
Business Name and Address	Navigant Bay Adelaide Centre 333 Bay Street Suite 1250 Toronto, ON M5H 2R2	Navigant Bay Adelaide Centre 333 Bay Street Suite 1250 Toronto, ON M5H 2R2	Navigant Bay Adelaide Centre 333 Bay Street Suite 1250 Toronto, ON M5H 2Y2	Navigant Bay Adelaide Centre 333 Bay Street Suite 1250 Toronto, ON M5H 2Y2
General Areas of Expertise	• Power project development and finance • Power procurement • Regulatory economics • Electricity market design and operations • Energy policy • Strategy and operations • Mergers and acquisitions	• Portfolio assessment and business planning • Cost-benefit analysis • Cost Allocation and affiliates • Regulatory economics • Integrated planning • Compliance and Risk • Project due diligence • Generation procurement and divestiture	• Regulatory finance • Grid modernization • Power systems and markets	• Regulatory economics • Regulatory studies & analysis • Markets and Economic Analysis • Cost-benefit analysis • Strategy and operations • Energy policy • Demand-side management

Qualifications:

Name	**Benjamin Grunfeld** Managing Director	**Craig Sabine** Director	**Andy Tam** Associate Director	**Jodi Amy** Associate Director
Professional History	• Managing Director, Navigant • Director, Navigant • Managing Consultant, London Economics International • Senior Associate, Ampersand Energy Partners • Junior Engineer, Power and Electro-technology, Hatch	• Senior Manager, • MNP LLP • Manager, ICF International • Environment Canada	• Associate Director, Navigant • Managing Consultant, Navigant • Senior Consultant, Navigant • Leadership Rotation Program, Hydro One Networks Inc.	• Associate Director, Navigant • Managing Consultant, Navigant • Senior Consultant, Navigant • Senior Business Analyst, Ontario Power Authority • Business Analyst, Ontario Power Authority
Education	• M.Sc., Management and Economics, London School of Economics and Political Science, London, UK • B.Sc., Engineering (Applied Mathematics and Electrical Engineering), Queen’s University, Kingston, ON	• M.B.A. Executive Program, Queen’s Smith School of Business, Kingston, ON • Environmental and Resource Studies. Minor, Biology University of Waterloo, ON	• M.B.A., Ivey School of Business, London, ON • B.Sc., Engineering (Computer), Queen’s University, Kingston, ON • B.A., Economics, Queens University, Kingston, ON	• M.B.A., Rotman School of Management, Toronto, ON • B.A., Economics, University of Waterloo, Waterloo, ON

The lead expert on this project was: Craig Sabine

Instructions Provided:
Navigant Consulting Ltd (Navigant) was requested to prepare a report that provides estimates of the level of cash working capital for Hydro One Networks regulated transmission operations.

Basis of Evidence:
The basis of evidence and assumptions have been documented in the above-noted report.

Context of Evidence:
The context of evidence has been documented in the above-noted report.

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:
Benjamin Grunfeld

Date:
February 21, 2019

FORM A

Proceeding:………………………

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Benjamin Grunfeld ....(*name*). I live at Toronto......................... (*city*), in the Ontario .... (*province/state*) of Canada ....

2. I have been engaged by or on behalf of ...Hydro One Networks (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: February 21, 2019

Signature

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Working Capital
Annual Average
Test Years (2020 to 2022)
($ Millions)

Line No.	Particulars	2020 (b)	2021 (c)	2022 (d)
1	Cash Working Capital	$ 24.4	$ 26.6	$ 27.8
2	Materials and Supply Inventory	12.0	12.2	12.4
3	**Total**	**36.4**	**38.8**	**40.2**

MATERIALS AND SUPPLIES INVENTORY

1. STRATEGY

Hydro One Transmission maintains and optimizes materials and supplies inventory in support of our reliability, system growth and customer satisfaction objectives. Having the right material at the right work location at the right time is important in meeting these objectives.

The 2015 to 2022 inventory levels reflect impacts of the increasing work programs with compressed timelines, the increasing transmission asset base and its asset condition, age, and the external cost pressures offset by initiatives to manage inventory growth. Various initiatives undertaken by Hydro One Transmission to manage its inventories include the following:

- Integration of planning and procurement processes to maintain the primary strategy of securing materials for transmission capital projects directly from vendors;
- Adjustments in transmission maintenance related inventories to increase flexibility in executing maintenance protocols;
- An increased focus on stocking materials remaining at the end of capital projects to improve the visibility and redeployment of available materials; and
- The use of stock algorithms to maximize inventory performance.

A further description of Hydro One Transmission's Supply Chain and initiatives undertaken are described in Exhibit C, Tab 9, Schedule 4.

2. INVENTORY

As of December 31, 2018, Hydro One Transmission has a total year-end inventory valued of $11.8 million. Table 1 provides the inventory levels for 2015 to 2022. Included are both the year-end levels and annual average levels for each year.

Table 1: Inventory Levels (Transmission) 2015 – 2022 ($ Million)

Year	Historic				Bridge	Test		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Year End	11.6	11.6	11.4	11.8	11.8	12.1	12.3	12.6
Annual Average[1]	12.2	11.6	11.5	11.6	11.7[2]	12.0	12.2	12.4

[1] *The average annual inventory level is calculated as the previous year-end level plus the current year-end level divided by two.*
[2] *The 2019 average is based on the 2018 forecast of $11.5 million.*

2.1 PLANNED LEVELS OF INVENTORIES

Much of Hydro One Transmission's materials and supplies are supplied directly from vendors. Inventory is established to provide faster response to planned and unplanned projects and programs from inventoried stock. The basis of forecasting inventory levels reflects planned work program changes.

Materials and supplies for major transmission projects are often shipped directly to the project sites and are not included in the planned inventory levels, where timelines permit.

Inventories are held for the maintenance of existing assets and new development activities. Inventory primarily includes component parts for major equipment and selected materials where lead times and response requirements dictate, as well as materials and equipment that remain at the end of a project.

2. 2 MONTHLY INVENTORY LEVELS 2015 TO 2018

In response to the Board's directive to the Company to provide the monthly material and supplies inventory balances as part of rate applications, actual monthly net inventory numbers for the years 2015 through 2018 are shown in Table 2. Table 2 does not include the strategic spare inventory of items such as transformers.

Table 2: Historical Monthly Inventory Levels 2015 – 2018

$M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	12.7	12.7	12.7	12.8	12.7	12.6	12.6	12.7	12.7	12.7	12.4	11.6
2016	11.4	11.3	11.3	11.2	11.2	11.2	11.2	11.2	11.3	11.2	11.5	11.6
2017	11.7	11.7	11.7	11.7	11.7	11.6	11.4	11.5	11.5	11.4	11.4	11.4
2018	11.5	11.5	11.4	11.4	11.4	11.5	11.6	11.6	11.5	11.5	11.4	11.8

The inventories of consumable materials are relatively steady due to the nature of transmission work. Failures and maintenance are driven by equipment condition, age, service and available outages. Capital projects are conducted year round, with a slight increase of capital work in the summer months and the winter cold months.

ECONOMIC EVALUATION TRUE-UPS/CCRA

INTRODUCTION

This Exhibit describes load true-up calculations relating to Customer Connection and Cost Recovery Agreements (CCRA), as well as a request for a variance account to track the impact of those true-ups on revenue requirement and rate base. Load true-ups are performed by Hydro One in accordance with the requirements of the Transmission System Code (TSC).

TRUE-UP PROCEDURE FOR LOAD CUSTOMERS

Hydro One carries out true-up calculations, based on actual customer load, for new and modified connection facilities at specific true-up points, as prescribed in section 6.5.3 of the TSC:

1. for high risk connections, at the end of each year of operation, for five years;
2. for medium-high risk and medium-low risk connections, at the end of each of the third, fifth and tenth year of operation; and
3. for low risk connections, at the end of each of the fifth and tenth year of operation, and at the end of the fifteenth year of operation if actual load is 20% higher or lower than the initial load forecast at the end of the tenth year of operation.

For the true-up calculation, Hydro One uses the same methodology used to carry out the initial economic evaluation, and the same inputs except for load, as per section 6.5.4 of the TSC and detailed in section 2.5 of Hydro One's OEB-approved Transmission

Connection Procedures. Hydro One Transmission carries out true-ups with Hydro One Distribution, as with any other customer.

The load used in the true-up calculation is based on the actual load up to the true-up point and an updated load forecast from the customer for the remainder of the economic evaluation period used. Hydro One Transmission assesses whether the updated load forecast is reasonable prior to inclusion in the true-up calculations. Only new load is included in the true-up calculation; if the customer has transferred existing load from another Hydro One-owned connection facility already serving the customer to the new or modified connection facility that is the subject of the true-up, the customer's actual load will be reduced by the amount of the transferred load. The updated load forecast will also be reduced to eliminate any transferred load. Also, the actual load of the customer is increased by the embedded generation and conservation and demand management activities in accordance with section 6.5.8 to section 6.5.10 of the TSC and detailed in Hydro One's CDM/DG Load Adjustments Guidelines for CCRA True-Ups.

When a load customer voluntarily and permanently disconnects its facilities from a transmitter's facilities prior to the last true-up point, Hydro One, at the time of disconnection, carries out a final true-up calculation in accordance with section 6.5.11 of the TSC.

When the true-up calculation shows that the customer's actual load and updated load forecast is lower than the load in the initial load forecast, and therefore does not generate the initial forecast connection rate revenues, the customer is required to make a payment to make up the shortfall, adjusted appropriately to reflect the time value of money and net of any previous capital contributions, including true-up payments, as per section 6.5.6 of the TSC. This capital contribution is credited against fixed assets and results in a reduction in rate base.

Where a true-up calculation shows that the customer's actual load and updated load forecast is higher than the load in the initial load forecast, and therefore generates more than the initial forecast connection rate revenues, Hydro One applies this credit against any shortfall in subsequent true-up calculations. After the final true-up calculation is completed, any credited amount is adjusted appropriately to reflect the time value of money and rebated to the customer. The rebate amount will not exceed the capital contribution, adjusted to reflect the time value of money, previously paid by the customer, as per section 6.5.7 of the TSC. Once the rebate has been paid to the customer, Hydro One will increase the net fixed assets of the connection facility, and thereby the rate base, by a corresponding amount.

REQUEST FOR A VARIANCE ACCOUNT

Hydro One proposes to create a new variance account to track the variance between the revenue requirement impact of capital contributions collected and the corporate income tax payments related to load true-ups performed in accordance with Transmission System Code section 6.5.3. During the three year period of this rate application, the majority of CCRA contracts will be required to complete at least one true up.

In EB-2016-0160, Hydro One forecasted the impact of true-ups on the two years of Revenue Requirement, including the return on capital with corporate income tax gross up, depreciation, and the one-time income tax impact due to capital contributions being considered as revenue for tax purposes. In the 2017 and 2018 test years, Hydro One forecasted 27 agreements requiring a true up with a net capital contributions of $11.7M and $7.2M respectively and reduced rate base and required depreciation accordingly (EB-2016-0160 Exhibit D1, Tab 1, Schedule 3).

The forecasted one-time payments to the Canadian Revenue Agency were included in the tax provision (EB-2016-0160 Exhibit C2, Tab 4, Schedule 1, Attachment 1). As per the *Income Tax Act*, adjustments to assets as a result of capital contributions may only occur within the first three years after in-service for tax purposes. Beyond that point, capital contributions are considered as revenue and taxed at the corporate tax rate (26.5%). Capital contribution refunds in accordance to TSC 6.5.7 would be considered an offset to revenue (lower tax payment required). Hydro One consulted with external advisors and Canada Revenue Agency on the possibility of receiving a technical interpretation that would allow Hydro One to treat receipts of CCRA true ups beyond year three as capital contributions for tax purposes. However, the legislation is clear and Hydro One was advised that Canada Revenue Agency would not be able to provide the requested technical interpretation in the absence of a legislative amendment.

In 2017, the net capital contributions of $11.7M for the tax provision were increased by a one-time payment of $3.1M ($11.7M * 26.5%) to cover forecasted corporate income tax payments for capital contributions in that year. 2018 resulted in an increase of $1.9M ($7.2M * 26.5%).

Actual capital contribution true-ups collected in 2017 were $0.5M with a corresponding tax impact of $0.2M. In 2018, actual capital contributions true-up collected were $11.1M with a corresponding tax impact of $2.9M. This resulted in a rate base reduction variance of $7.3M over a two year period ($18.9M forecast for 2017 & 2018 minus $11.6M actuals) and a tax variance of $1.8M ($18.9M forecast for 2017 & 2018 * 26.5% minus $11.6M actuals * 26.5%). This major variance to forecast was driven by the following factors:

- Several load true-ups that were forecasted to be completed in December 2017 were delayed into 2018 in order to obtain Conservation and Demand Management program results from the IESO as well as the necessary detailed data for embedded distributed generation in accordance with TSC 6.5.9.

- Several customers exceeded forecasted performance on actual Conservation and Demand Management results as verified by IESO as per TSC 6.5.9, greatly decreasing the required capital contribution true-up required to be applied.
- Most customers provided updated load forecasts showing increasing demand due to improving economic conditions as well as Conservation and Demand Management performance as per TSC 6.5.9 further reducing their capital contribution obligation.

Note: No Hydro One Distribution load true ups were scheduled nor required in 2017 or 2018.

After reviewing the variance of forecasted true up payments and actual true up payments, it was determined that while Hydro One is able to perform a macro forecast of the total transmission load in Ontario, an individual analysis of the forecasted 68 true ups required during the 2020 – 2022 test period and resulting capital contribution calculation subjects both the shareholder and ratepayer to a number of significant forecasting risks that are beyond the control of Hydro One. The primary risks are as follows:

1. Actual load is adjusted by embedded generation and energy conservation as per TSC 6.5.8 to 6.5.10. Hydro One does not have access to individual company reports from the IESO on an ongoing basis and is typically provided with this information by the customer only if it is applying for load credits during the true-up.

2. Customer load forecasts at the true-up point are subject to significant change based upon the customer's outlook of its specific operations (productivity vis-a-

vis competitors, refurbishments or planned expansions to their operations etc.) These customer forecasts extend beyond the Hydro One rate setting load forecasts (i.e. an industrial 5th year true up could have a forecast for a decade, years 6 to 15 as per the TSC). However, the customer forecast has an impact on the required true up capital contribution, rate base, and tax expense in the year that the true up is performed.

3. The customer load forecasts at the true up-point are subject to significant changes based upon specific market factors that the customer operates in (such as mineral pricing forecast for mining, demand for its particular product, exchange rate fluctuations etc.) of which Hydro One has limited insight into.

4. For many CCRA contracts, there is insufficient actual load data since the latest true-up to perform a forecast for this rate filing. For customers that have a higher risk classification or that were trued up in 2017 or 2018, the comparison of actual performance versus forecast has a high probability of error since there is usually less than one year of actual performance data. For example, low risk customers scheduled for a 2022 true-up last had their load true up performed in 2017 and therefore there is less than one year of performance data on the updated load forecast available to forecast the remaining performance of the contract.

5. Transmission expansions or upgrades requested by industrial customers will be executed and placed in service with an initial economic evaluation and load trued up within the four year rate period of this application. For example, a mine requests a line expansion to connect their facility in the first year and connected in the second year of this rate hearing, could have several load true ups performed in the subsequent years depending upon their Risk Classification (i.e. a high risk classification could result in two load true up under this scenario).

The proposed variance account will track the revenue requirement impacts of actual capital contributions or rebates paid when performing load true ups, including the one-time tax impact. The variance account will not include the impact of the Notional Account, TSC 6.5.7, prior to the final true up. Notional Accounts do not trigger a payment by Hydro One and therefore do not adjust rate base nor result in a tax implication. Exhibit H, Tab 1, Schedule 2 includes formal request for the CCRA True-up Variance Account including a draft accounting order.

This account will not include the impact of the initial economic evaluation based upon actual costs as these will be revenue requirement and tax neutral to the shareholder and ratepayer. For capital contributions collected in accordance with TSC section 6.5.2 for the initial economic evaluation as well as when the transmitter subsequently recalculates the customer capital contribution based on actual cost, these are individually disclosed for each project in the relevant Investment Summary Documents (See Section 3.3 of the TSP). Each of these capital contributions are an offset to rate base when the asset is placed into service.

INTEREST CAPITALIZED

Consistent with the Board's Decision in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction ("AFUDC") rate is specified for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is consistent with Hydro One's adoption of United States Generally Accepted Accounting Principles ("US GAAP") per the Board's decision in EB-2011-0268 and US GAAP requirements for determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Hydro One Transmission's forecasted average debt portfolio during the year.

Capitalized interest is included in the capital expenditures shown in Section 3.1 of the Transmission System Plan (the "TSP") provided as Exhibit B, Tab 1, Schedule 1. These expenditures are recovered through Revenue Requirement once they become in-service additions to Rate Base.

Table 1: Capitalized Interest

Year	Capitalization Rate	Transmission Capitalized Interest ($ Millions)
2014	4.7%	33.7
2015	4.7%	37.1
2016	4.4%	44.2
2017	4.4%	45.4
2018	4.4%	45.5
2019 Forecast	4.6%	38.3
2020 Forecast	4.6%	43.6
2021 Forecast	4.7%	48.5
2022 Forecast	4.8%	51.3

Witness: Samir Chhelavda

OVERHEAD CAPITALIZATION RATE

This Exhibit describes the methodology used to allocate Common Corporate Costs to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overhead costs supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its April 9, 2010, Decision on Hydro One's 2010 and 2011 distribution rates (EB-2009-0096), the Board accepted the methodology, recommendations and the allocation of costs from a study by Black & Veatch (B&V, formerly RJ Rudden Associates). The study derived an overhead capitalization rate for Hydro One Distribution's common corporate costs. The accepted methodology was used in the recent application for Distribution Rates for 2018 to 2022 (EB-2017-0049) as well as prior Transmission rate applications including the 2015-2016 transmission rate application (EB-2014-0140) and the 2017-2018 transmission rate application (EB-2016-0160).

In 2007, Hydro One Networks began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support.

Hydro One proposes that the overhead capitalization methodology, as reviewed in the B&V study in 2018, continues to be a reasonable method of distributing common corporate costs to capital projects. Hydro One's submissions in this Application reflect this overhead capitalization methodology.

Table 1 below summarizes the overhead capitalization rates and amounts as calculated by the methodology reviewed by B&V. Appendix 1 to this Exhibit shows further detail of the B&V study applied in 2018.

Table 1: Overhead Capitalization Rates & Amounts

Overhead Cost Category	Bridge (%)	Test Years (%)			Bridge ($ millions)	Test Years ($ millions)		
	2019	2020	2021	2022	2019	2020	2021	2022
Capitalized Administrative & General Costs[1]	9%	8%	8%	8%	91.3	96.6	99.3	100.1
Capitalized Planning, Customer and Operating Costs[2]	2%	2%	2%	2%	22.9	22.8	23.2	23.7
Total	11%	10%	10%	9%	114.1	119.4	122.6	123.8

[1] Administrative & General Costs include all common corporate functions and services costs

[2] Operating costs include asset management, network operating and customer care management costs

The capitalization rates are down relative to the previous transmission study mainly due to higher planned capital expenditures and lower OM&A.

In its EB-2011-0268 decision, the Board granted Hydro One Transmission approval to adopt United States Generally Accepted Accounting Principles (US GAAP) as its approved basis for rate setting, regulatory accounting and regulatory reporting commencing January 1, 2012. In this decision, the Board also directed Hydro One Transmission to conduct a critical review of its then current and proposed capitalization practices. The Board stated that the review should not be a benchmarking study, but should include information, for comparison purposes, on what US transmitters typically capitalize and capitalization methodologies employed by other transmitters. (See page 13 of the decision.)

A summary of the results of this review (which covered both transmission and distribution entities) was filed as part of Hydro One Transmission's 2013-2014 rate application (EB-2012-0031). The same methodologies were used to allocate Common Corporate Costs and Other OM&A costs to the transmission overhead capitalization rate in 2015 and 2016 Transmission rate application (EB-2014-0140). It was determined to be appropriate by the intervenors and Board Staff who participated in the Settlement Conference, and was accepted by the Board in its Decision. Additionally, the same methodology was approved as part of Hydro One Transmission's 2017 and 2018 rate application (EB-2016-0160) and was used in the recent application for Distribution Rates for 2018 to 2022 (EB-2017-0049).

As documented in the review report, Hydro One critically reviewed its cost capitalization policy with a particular focus on the capitalization of overhead and indirect costs. In its review, Hydro One found that its treatment of overhead capitalized is generally consistent with other major US and Canadian industry participants. Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities.

Hydro One also concluded that its overhead and indirect cost capitalization methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with: (a) legacy Canadian and existing US GAAP; and (b) regulatory principles, including the key goals of achieving intergenerational equity and avoiding cross subsidization.

REVIEW OF OVERHEAD CAPITALIZATION RATES (TRANSMISSION) – 2019

BLACK & VEATCH PROJECT NO. 188588

PREPARED FOR

Hydro One Networks Inc.

JANUARY 31, 2019

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Building a world of difference.®

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I. OVERVIEW

A. INTRODUCTION

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report which describes our Review of Overhead Capitalization Rates (Transmission) - 2020-2022. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Transmission and Distribution capital expenditures; the results are the amounts of Common Corporate Costs that are capitalized to those capital expenditures for the year.

The methodology was developed for Hydro One by Black & Veatch, first presented in our report *Distribution Overhead Capitalization Rate Method* dated May 20, 2005 and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology for development of the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with reports issued, as follows:

Table 1 - History of Black & Veatch's Cost Allocation Reviews for Hydro One

BLACK & VEATCH REVIEW	HYDRO ONE FILING	BLACK & VEATCH REPORT
2006 Review	2006 Transmission Rates	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review	2008 Transmission Rates	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review (Distribution)	2010/2011 Distribution Rates	*Review of Overhead Capitalization Rates* dated June 29, 2009
2009 Review (Transmission)	2011/2012 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010
2011 Review (Transmission)	2013/2014 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission)– 2013-2014* dated February 1, 2012
2013 Review (Distribution)	2015-2019 Distribution Rates	*Review of Overhead Capitalization Rates (Distribution)– 2015-2019* dated September 19, 2013
2013 Review (Transmission)	2015/2016 Distribution Rates	*Review of Overhead Capitalization Rates (Transmission)– 2015-2016* dated March 17, 2014
2015 Review (Transmission)	2017/2018 Distribution Rates	*Review of Overhead Capitalization Rates (Transmission)– 2017-2018* dated May 4, 2016
2016 Review (Distribution)	2018-2022 Distribution Rates	*Review of Overhead Capitalization Rates (Distribution)– 2018-2022* dated December 21, 2016

Hydro One computed the Transmission OH Cap Rate to be 10% for 2020 (*Appendix A, row 108*). The calculation of the rates is described in Section II of this report and shown in Appendix A.

Based on the work performed, Black & Veatch believes that Hydro One's implementation of the Overhead Capitalization Rate methodology and computation of the Transmission OH Cap Rates for 2020-2022 are appropriate and conform to the OEB-accepted methodology.

B. BACKGROUND

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Transmission Capital spending is budgeted to be approximately between $1.2 billion annually in 2020, representing approximately 10% of Transmission Net utility plant.

Most of Hydro One's capital program is performed by Hydro One employees, and not contracted out. Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Transmission Operations and Maintenance ("Tx OMA") and Transmission Capital Expenditures work.

C. CRITERIA FOR COST ALLOCATION METHODS

The portion of Common Corporate Costs attributed to Transmission was determined based on the OEB-accepted methodology, as described in the Black & Veatch's *Review of Allocation of Common Corporate Costs (Transmission) - 2019* dated January 31, 2019 ("2019 Common Corporate Costs Report- Transmission").

The Transmission OH Cap Rate is used to distribute the Transmission portion of Common Corporate Costs, between Transmission OMA and Transmission Capital Expenditures. Following are the criteria that Black & Veatch used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the costs that has been incurred.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is benefits received (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. DESCRIPTION OF OH CAP RATE METHOD

Approximately $89 million of labour costs, representing approximately 33% of the annual total Common Corporate Costs (and approximately 42% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-week period ending June 9, 2017 ("2017 Time Study"). The 2017 Time Study included the following departments:

Table 2 – Departments in Time Study

Operations	Customer and Corporate Relations
Distribution Asset Management	Customer Care Services
Strategy & Integrated Planning	Market Solutions
System Planning	Customer Program Delivery
Systems Operations	Key Account Management
Transmission Asset Management	VP Customer Service
VP Planning	Meter to Bill
COO Office - Operations	

A properly performed time study measures cost causation and is widely accepted as a basis for assigning costs. Hydro One personnel administered the 2017 Time Study using the same design and communication material designed by Black & Veatch and utilized in the time study that occurred in 2015. Black & Veatch's responsibilities included reviewing time study results and the consolidation of the results, and confirming the completeness of the time study and its consistency with the study design. The methodology was the same as used in prior time studies conducted by Black & Veatch for Hydro One. Black & Veatch found that the 2017 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized to Transmission capital expenditures. The last Time Study was conducted in 2017 prior to the Hydro One Accountability Act and the associated changes to the Common Corporate Cost Model described in the 2019-Common Corporate Costs Report-Transmission. Given the changes to the Common Corporate Cost Model were focused on the direct assignment of specific executive costs to Shareholders, there are no changes to the organizational structure or time spent that would warrant a new time study.

While the remaining Common Corporate Costs departments can determine with reasonable accuracy the portions of time spent on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects. Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. Black & Veatch considered the following two bases for allocating Common Corporate Costs between OMA and capital projects:

- **Labor Content Method-** Labor Content of Transmission (Tx) OMA versus Tx capital expenditures
- **Total Spending Method-** Total Spending on Tx OMA versus Tx capital expenditures

The Common Corporate Costs to be allocated are causally related to both Labor Content and Total Spending. Therefore the OH Cap Rate method for Common Corporate Costs recommended by Black & Veatch uses a weighting of 50% Labor Content and 50% Total Spending, as there is no evidence that either the Labor Content method or the Total

Spending method is meaningfully more appropriate.

- The formula for Transmission (Tx) Labor Content is:

  Tx Labor Content = Tx Labor $ in Tx Capital Expenditures / (Labor $ in Tx Capital Expenditures + Labor $ in Tx OMA)

- The formula for Tx Total Spending is:

  Tx Total Spending = Tx Capital Expenditures / (Tx Capital Expenditures + Tx

  OMA) The table below shows the results of the computations for 2020-2022.

Table 3 – Total Spending Method Labour and Spending Breakdown

PORTION OF COMMON CORPORATE COSTS SERVICES CAPITALIZED- TRANSMISSION	2020
Labor Content- Capital	73.84%
Total Spending- Capital	79.78%
50/50 Average	76.81%

Sensitivity Analysis

As a sensitivity analysis, Black & Veatch analyzed two sensitivity cases - the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

Table 4 – Sensitivity Analysis

CASES	LABOR CONTENT /	TRANSMISSION-2020	
		% costs Capitalized	2020 OH Cap Rate
Recommended	50%/50%	76.81%	9.68%
High Labor Case	75%/25%	75.33%	9.51%
Low Labor Case	25%/75%	78.27%	9.84%

Black & Veatch also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of Common Corporate Costs services. For example, a transformer that is purchased for use in a capital project from a pre-approved vendor requires very little of these services, but receives the same rate of overhead capitalization as a project requiring substantial support. In applying the OH Cap Rates, there will be differences compared to performing a specific analysis for each project. However, the Black & Veatch method is appropriate because:
   - Black & Veatch's recommended Labor / Total Content method correctly computes the total Common Corporate Costs dollars to be capitalized, and the amount charged to specific expenditures has virtually no effect on the financial statements or on ratepayers.
   - Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to these minor assets. Other assets (i.e., non-Minor Fixed Assets) are usually parts of larger projects, therefore the use of average OH Cap Rates is appropriate, because larger expenditures are more likely to have an average usage of Shared Services.
   - It is impractical to perform an analysis for each project.
2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. Black & Veatch recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content.

Black & Veatch believes that allocating Common Corporate Costs to capital expenditures based on 50% Labor Content/50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the costs being capitalized.

E. USE OF BUDGETED NUMBERS

The OH Cap Rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the OH Cap Rates quarterly to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustment is needed in subsequent years.

II. COMPUTATION OF TRANSMISSION OH CAP RATE

This Section presents, as an example, the computation of the Transmission OH Cap Rate for 2020. The calculation of the rate uses the same method for all years in BP 2020-2022.

A. FORMULA

The following formula is used to compute the 2020-2022 Transmission OH Cap Rates:

a. *Transmission OH Cap Rate*= (Capitalized Transmission CCC-A&G Costs + Capitalized Transmission CCC-Operating Costs) / Transmission Capital Expenditures

Note: A&G = Administrative & General

Where

b. *Capitalized Transmission CCC-A&G Costs* = Transmission CCC-A&G Costs capitalized = (Transmission Labor Content Ratio X 50% + Transmission Total Spending Ratio X 50%) X Transmission CCC-A&G Costs

c. *Transmission CCC-A&G Costs* = Total Transmission CCC Costs less Transmission CCC-Operating Costs departments

d. *Capitalized Transmission CCC-Operating Costs* = Transmission CCC-Operating Costs capitalized, based on the results of the 2017 Time Study

e. *Transmission CCC-Operating Costs* = The budgets for departments, included in the 2017 Time Study

f. *Transmission Capital* = Cost of Transmission capital expenditures supported by Common Corporate Costs (i.e., CCC-A&G Costs plus CCC-Operating Costs); also, total cost of Transmission capital expenditures to which the Transmission OH Cap Rate is applied

g. *Transmission Labor Content Ratio* = Transmission Labor $ in Transmission Capital Expenditures / (Labor $ in Transmission Capital Expenditures + Labor $ in Transmission OMA)

h. *Transmission Total Spending Ratio* = Transmission Capital Expenditures / (Transmission Capital Expenditures + Transmission OMA)

These terms are further discussed below.

B. RECOMMENDED METHOD

This section discusses the method recommended by Black & Veatch to compute the Transmission OH Cap Rate. References below are to Appendix A, and the amounts and percentages cited are for 2020. The calculations use projected data. Because the methodology includes a true-up at the end of the year (Section I.E), the amounts recorded by Hydro One reflect actual data.

1. TRANSMISSION CAPITAL

(Appendix A, rows 1-9)

Transmission Capital (Formula f in Section II.A) represents the cost of Transmission business Capital Expenditures that are supported by Transmission business CCC activities (CCC-A&G activities and CCC-Operating activities), and is the total cost of Transmission business Capital Expenditures to which the Transmission OH Cap Rate is applied. Transmission Capital equals total spending for Transmission Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCC-A&G or CCC-Operating support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the CCC-A&G and CCC-Operating effort required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires support from CCC-A&G and CCC-Operating.

2. TRANSMISSION SPENDING FOR OMA

(Appendix A, rows 11-18)

Transmission Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 45-49). The amounts are based on the BP 2020, with adjustments to remove those costs which are included in Applicable CCC-A&G costs (row 37).

3. APPLICABLE TRANSMISSION CCC-A&G COSTS

(Appendix A, rows 21-37)

Applicable Transmission CCC-A&G Costs (Formula c) (row 37) represents the Transmission CCC-A&G Costs subject to capitalization, and equals total Common Corporate Costs distributed to the Transmission Business in the Common Corporate Costs Model, adjusted as follows:

- Transmission CCC-Operating Costs (Formula e) are removed because the capitalization ratios for those departments were determined in the 2017 Time Study.
- Transmission Facilities costs that are removed from the CCC-A&G Costs, relating to Operations facilities, are added back, because they are used to support activities that support Capital Expenditures.
- Transmission CCC-A&G Costs for the following departments that do not support capital expenditures are removed: Inergi- Customer Support Operations (CSO), Inergi-ETS to support CSO Applications, Inergi-ETS to support market transition costs and Inergi- Settlements. (Note- No costs of CSO or Inergi-ETS-CSO were allocated to Transmission in the Corporate Common Costs model.)

4. TRANSMISSION LABOR CONTENT- CAPITAL RATIO

(Appendix A, rows 39-43)

Transmission Labor Content-Capital Ratio is the portion of total Transmission labor costs included in Transmission Capital Expenditures (Formula g). The Labor $ on Rows 40-41 were developed by

Hydro One. The Labor $ are fully burdened labor costs (salary plus benefits).

5. TRANSMISSION TOTAL SPENDING- CAPITAL RATIO

(Appendix A, rows 45-49)

Transmission Total Spending-Capital Ratio is the portion of Transmission total spending included in Transmission Capital Expenditures. In the formula, Transmission spending for OMA (row 46) is from row 18 and Transmission spending for capital expenditures (row 47) is from row 9.

6. CAPITALIZED TRANSMISSION CCC-A&G

Capitalized CCC-A&G Costs (Formula b) is the portion of Transmission CCC-A&G Costs to be capitalized. The portion of Transmission CCC-A&G Costs to be capitalized (row 55) is the average of Transmission Labor Content-Capital Ratio (from row 43) and Total Spending Capital Ratio (from row 49), using the appropriate weights (rows 52-53). This portion is multiplied by the Applicable CCC-A&G Costs (row 37) to compute Capitalized CCC-A&G Costs (row 59).

7. CAPITALIZED TRANSMISSION CCC-OPERATING

(Appendix A, rows 69-89)

Capitalized Transmission CCC-Operating Costs (Formula d) represents the amount of Transmission CCC- Operating Costs capitalized to Transmission Capital Expenditures. The 2017 Time Study showed that 39.3% of Asset Development and Management time, 17.5% of Network Operations time and 3.0% of Customer Care time, are related to Transmission Capital Expenditures. These percentages are applied to the BP 2020-2022 annual budgeted amounts for those groups, and the results are the amounts of CCC-Operating Costs to be capitalized (rows 79-83).

8. TRANSMISSION OH CAP RATE

(Appendix A, rows 97-108)

The Transmission OH Cap Rate (Formula a) equals (A) the sum of items 6 and 7 above, divided by (B) Capital spending. The Transmission OH Cap Rates for 2020-2022 (row 108) are in the table below.

Table 5 – Transmission OH Cap Rate

TRANSMISSION OVERHEAD	2020	2021	2022
Rate	10.0%	10.0%	9.0%

Appendix A - Transmission Overhead Capitalization Rates – BP 2020

	($ millions)	2020
1	Capital Expenditures	
2		
3	Total capexp	1192.5
4	Less: Minor fixed assets	(18.5)
5	Less: Capitalized overhead	(119.4)
6	Less: Capitalized interest	(43.6)
7	Add: Capital contributions	168.9
8	Add: Removal costs	54.1
9		1234.0
10		
11	OM&A	
12		
13	Total OM&A	375.9
14	Less: CCFS costs	(99.8)
15	Less: Facility costs	(26.5)
16	Less: Asset Mangt costs (excl. facility costs)	(56.2)
17	Add: Capitalized overheads	119.4
18		312.8
19		
20		
21	Capitalized CCFS Costs	
22		
23	Total Costs per CCCM	156.1
24	Less: Asset Development and Management	(24.2)
25	Less: Customer Care/CBR	(6.8)
26	Less: Operator	(25.2)
27	Net CCFS Costs	99.8
28	Add: Facility costs	26.5
29		
30	Less operating-type CCFS costs:	
31	Inergi - CSO	0.0
32	Inergi - ETS CSO Apps	0.0
33	Inergi - ETS Market Ready	0.0
34	Inergi - Settlements	(0.5)
35		(0.5)
36		
37	Applicable CCFS costs	125.8
38		
39	Portion capitalized based on labour content:	
40	Labour in OM&A	146.0
41	Labour in capexp	412.2
42		558.1
43	% capexp	73.8%
44		
45	Portion capitalized based on total spending:	
46	OM&A	312.8
47	Capexp	1234.0
48		1546.8
49	% capexp	79.8%
50		
51	Weighting:	
52	Labour content	50.0%
53	Total spending	50.0%
54		
55	Portion capitalized based on w eighting of tw o me	76.8%

56		
57	Applicable CCFS costs	125.8
58		
59	Capitalized CCFS costs	96.6
60		
61	Capitalized Asset Management Costs	
62		65.61%
63	Network Asset Management Costs (Tx + Dx):	
64	Asset Management (excl. facility costs)	36.3
65	Operating	41.6
66	Customer Care Management/CBR	40.2
67		118.1
68		
69	Portion capitalized (per time study):	
70	Asset Management (excl. facility costs)	39.3%
71	Operating	17.5%
72	Customer Care Management/CBR	3.0%
73		
74	Portion to OM&A (per time study):	
75	Asset Management (excl. facility costs)	27.5%
76	Operating	43.1%
77	Customer Care Management/CBR	13.7%
78		
79	Capitalized Asset Management costs:	
80	Asset Management (excl. facility costs)	14.3
81	Operating	7.3
82	Customer Care Management/CBR	1.2
83		22.8
84		
85	Non-Capitalized Asset Management costs:	
86	Asset Management (excl. facility costs)	10.0
87	Operating	17.9
88	Customer Care Management/CBR	5.5
89		33.4
90		
91	E-Factor	
92		
93	Amount to be capitalized from prior year	0.0
94	Amount actually capitalized in prior year	0.0
95		0.0
96		
97	Overhead Capitalization Rate	
98		
99	Capitalized CCFS costs	96.6
100	Capitalized Asset Management costs	22.8
101	E-Factor	0.0
102	TOTAL OVERHEADS	119.4
103		(119.4)
104	Capexp	1234.0
105		
106	Calculated overhead capitalization rate	9.7%
107		
108	Rounded	10.0%

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program,

OM&A Before Capitalization	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year
Sustainment	$ 215.1	$ 218.1	$ 229.4	$ 200.6	$ 214.2
Development	$ 4.6	$ 5.1	$ 5.2	$ 6.0	$ 6.9
Operating	$ 62.5	$ 61.1	$ 53.4	$ 46.1	$ 48.9
Customer	$ 4.5	$ 8.5	$ 11.0	$ 7.3	$ 7.5
Planning / Asset Management	$ 32.9	$ 32.0	$ 31.0	$ 25.5	$ 25.0
Information Technology (including Cornerstone)	$ 56.8	$ 58.5	$ 50.4	$ 45.6	$ 46.7
Common Corporate Functions and Services	$ 92.9	$ 90.2	$ 96.0	$ 87.9	$ 92.8
Internal + External Work COS	$ 4.8	$ 3.6	$ 8.4	$ 3.9	$ 3.9
Property Taxes	$ 61.3	$ 50.7	$ 65.3	$ 67.2	$ 68.1
Other	-$ 10.2	-$ 17.8	-$ 6.5	-$ 19.4	-$ 18.7
Directive				-$ 0.1	-$ 0.1
Total OM&A Before Capitalization (B)	$ 525.2	$ 510.0	$ 543.6	$ 470.6	$ 495.3
Check to OM&A	$ 408.1	$ 385.0	$ 419.2	$ 356.5	$ 375.8

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

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

Capitalized OM&A	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Capitalized Administrative & General Costs	-$ 91.3	-$ 98.1	-$ 99.3	-$ 91.3	-$ 96.6	No	No change
Capitalized Planning, Customer and Operating Costs	-$ 25.8	-$ 26.9	-$ 25.2	-$ 22.9	-$ 22.8	No	No change
Total Capitalized OM&A (A)	-$ 117.1	-$ 125.0	-$ 124.5	-$ 114.1	-$ 119.4		
% of Capitalized OM&A (=A/B)	-22%	-25%	-23%	-24%	-24%		

COSTING OF WORK

1. OVERVIEW

Hydro One Transmission's work program is bundled into packages of work identified as programs or projects. Programs are recurring investments while projects are typically one-time investments. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. This Exhibit details each of these three cost activities, and how the costs are allocated across programs and projects. This costing approach is consistent with the requirements of US Generally Accepted Accounting Principles ("USGAAP").

Hydro One categorizes its costs into two major classifications: common costs and direct costs. Common costs, both OM&A and capital expenditures, are allocated to Hydro One Transmission and Hydro One's other segments, as described in Exhibit F, Tab 2, Schedule 6. For clarity, the current Exhibit only describes the allocation of direct costs.

Direct costs charged to work orders include labour (comprising of salaries, benefits and pension costs), material, fleet and supply chain costs. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the work program or project. Fleet costs are charged using a fleet rate. Supply chain costs are charged via a material surcharge. The labour rate, fleet rate and material surcharge are described in detail in Exhibit C, Tab 9, Schedules 2 to 4.

2. OTHER PROGRAM AND PROJECT COSTS

Depending on the nature of the work, Hydro One Transmission's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material.

In terms of estimating and costing of capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. In these cases, the cost of removal work is accounted for as depreciation, and customer contributions are netted against gross capital costs.

Capital work also receives a monthly charge for its share of interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit C, Tab 8, Schedule 1 and Exhibit C, Tab 8, Schedule 2.

2.1 STANDARD RATES

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs based on the program and project cost activities responsible for generating the variances.

COSTING OF WORK: LABOUR RATE

1. LABOUR RATE

Labour costs for Hydro One's work execution functions are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour rates are used to allocate costs to Hydro One's work programs and projects. This Attachment outlines Hydro One's methodology in deriving the labour rate and provides an example of a typical rate and its components.

The labour rate is "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost-effectively distributed. Included in the "fully loaded" costs are elements associated with compensation. Hydro One's workforce planning and employee compensation strategies are discussed in Exhibit F, Tab 4, Schedule 1 which outlines the total costs of compensation reflected in the Hydro One Transmission business plan, including, but not limited to, the components of payroll obligations such as base pay, overtime, burdens, pension and OPEB and other costs like short-term incentive payments for management staff.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. Table 1 shows an example of the composition of a standard labour rate for one category, the Regional Maintainer Electrical Stations – Regular Staff, over the period 2015 to 2022.

Table 1: Standard Hourly Labour Rate Composition
Regional Maintainer Electrical (Stations) – Regular Staff

	Historic				Bridge	Test		
	2015	**2016**	**2017**	**2018-Forecast**	**2019**	**2020**	**2021**	**2022**
Payroll Obligations	79.63	78.61	79.23	78.08	76.11	76.63	77.15	77.68
Contractual time away from work	9.49	9.03	9.09	9.43	9.70	9.80	9.89	9.99
Time not directly benefiting a specific Program or Project	8.66	7.57	7.63	7.91	8.14	8.22	8.30	8.38
Field Supervision and Technical Support	18.01	15.39	15.51	14.44	14.67	14.82	14.96	15.10
Support Activities	18.21	17.40	16.54	16.14	16.37	16.53	16.69	16.85
Hourly Rate	**134.00**	**128.00**	**128.00**	**126.00**	**125.00**	**126.00**	**127.00**	**128.00**

The cost elements embedded in the standard labour rate as illustrated in Table 1 are explained in this Exhibit, using the position of Regional Maintainer Electrical – Regular Staff and its 2019 cost composition, as an example. The reduction in the labour rate from 2015 to 2016 largely relates to a reduction in operating costs resulting from revised pension valuation reports, as well as a reduction in the number of supervisory staff within the Field Supervision and Technical Support category. Further reductions from 2016 to 2019 represent an increased billable ratio resulting from less downtime and more time charged to projects, as well as a further reduction to payroll benefits.

1.1 PAYROLL OBLIGATIONS ($76.11)

A brief description of the cost elements included in this position category is provided below. Hydro One’s compensation, wages and benefits costs are more fully explained in Exhibit F, Tab 4, Schedule 1.

a) Base Labour and Payroll Allowances (64.4% of Payroll Obligations)

Base pay is contractually negotiated and reflected in wage schedules. Payroll allowances are also contractually negotiated and stated in collective agreements. Regular staff (e.g., PWU) is entitled to travel, footwear, and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

b) Company Benefits (29.6% of Payroll Obligations)

For regular staff, this is comprised of pension and current and post-employment benefits and health, dental, etc. For non-regular staff (for example, casual trades), this is comprised of pension and welfare contributions made on behalf of the non-regular employee. These contributions are significantly lower than those made on behalf of regular employees.

c) Government Obligations (6% of Payroll Obligations)

This consists of Canada Pension Plan, Employment Insurance, Employee Health Tax and Workplace Safety and Insurance Board contributions.

1.1.1 CONTRACTUAL TIME AWAY FROM WORK ($9.70)

This category consists primarily of employee vacation and statutory holidays, and all are established and identified in the relevant collective agreements. Sickness and accident costs are also included and are based on historical trends.

1.1.2 TIME NOT DIRECTLY BENEFITING A SPECIFIC PROGRAM OR PROJECT ($8.14)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

1.1.3 FIELD SUPERVISION AND TECHNICAL SUPPORT ($14.67)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

1.1.4 SUPPORT ACTIVITIES ($16.37)

a) Administrative Expenses and Support (68.3% of Support Activities)

These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for clerical support activities and other centralized support to facilitate work management system requirements.

b) Work Methods and Training (14.5% of Support Activities)

These are costs to design, develop, continually update, maintain and deliver work methods and training programs. Costs are assigned based on the forecast consumption of these services as agreed to by the work methods and training function and service recipient.

c) Health, Safety and Environmental Support (17.2% of Support Activities)

These are costs to design, develop, update, maintain and deliver health, safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the health, safety and environment function and the service recipient.

COSTING OF WORK: FLEET RATE

1. OVERVIEW: FLEET RATE

Hydro One controls and manages approximately 7,000 transport and work equipment (TWE) and 7 helicopters to support its work programs and staffing requirements. Fleet assets are used for both distribution and transmission work and are strategically located across Hydro One's service territory. The total fleet complement was decreased by 10% in 2017, due to a Fleet right-sizing initiative leveraging Telematics technology, detailed in section 2.7.2 of this Exhibit.

Fleet assets are categorized into 56 classes of equipment. A standard equipment rate, or "Hourly Fleet Rate", is calculated for each class of equipment. Each rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours that the class of equipment is required to work (utilization hours). Utilization hours are defined as the hours the equipment is in use "on the job". Utilization hours are forecasted based on a review of historical trends and an annual review of the upcoming work program. To illustrate, Table 1 shows the composition of the hourly fleet rate for a line maintenance truck, one of the common classes of equipment used by Hydro One.

Table 1: Hourly Fleet Rate - Line Maintenance Truck

Description	**Historic**				**Bridge**	**Test**		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Operations & Repairs	36.0	38.0	38.0	35.1	36.9	37.6	37.6	38.2
Fuel Costs	8.9	6.9	6.9	7.0	6.8	6.9	6.9	7.0
Depreciation	20.1	12.1	12.1	14.9	13.3	13.6	13.6	13.8
Hourly Rate	**65.0**	**57.0**	**57.0**	**57.0**	**57.0**	**58.0**	**58.0**	**59.0**

In 2019, it is forecasted that operations and repair costs will make up 65% of the truck rate, while fuel costs and depreciation costs will comprise 12% and 23%, respectively.

Table 2 and Table 3 provide total expenditures of the components comprising the fleet rate for historic, bridge and test years for Transport & Work Equipment and Helicopter Services.

Table 2: Transport & Work Equipment ($ Millions)

Description	Historic				Bridge	Test
	2015	2016	2017	2018	2019	2020
	Actual	Actual	Actual	Actual	Forecast	Forecast
Operations & Repairs	69.7	70.8	69.5	67.7	69.8	68.1
Fuel Costs	25.0	21.5	22.9	27.2	25.7	25.1
Depreciation	37.8	39.7	40.6	40.3	40.7	41.4
Subtotal	**132.5**	**132.0**	**133.1**	**135.2**	**136.2**	**134.6**
External Fleet Rentals	0.6	1.2	0.6	0.5	1.0	0.5
Total	**133.1**	**133.2**	**133.7**	**135.7**	**137.2**	**135.1**

Table 3: Helicopter Services ($ Millions)

Description	Historic				Bridge	Test
	2015	2016	2017	2018	2019	2020
	Actual	Actual	Actual	Actual	Forecast	Forecast
Operations & Repairs	7.6	7.3	7.2	7.6	7.9	7.9
Fuel Costs	0.8	1.1	1	1.1	1.2	1.2
Depreciation	0.9	1.2	1.2	1.2	1.2	1.2
Subtotal	**9.3**	**9.6**	**9.3**	**9.9**	**10.1**	**10.2**
External Fleet Rentals	0.1	0.1	0.0	0.0	0.0	0.0
Total	**9.4**	**9.7**	**9.3**	**9.9**	**10.2**	**10.2**

2. FLEET RATE COMPONENTS

2.1 OPERATIONS AND REPAIRS

This cost category primarily consists of repair costs (external and internal labour and parts). The budget is based on a forecast of the annual maintenance schedules for each piece of equipment with consideration given to age and performance history. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations costs include administration staff and their allocated share of central service support costs. The increase in forecast for the 2019 bridge year is attributable to additional costs related to the telematics system described in section 2.7.2 of this Exhibit.

2.2 DEPRECIATION

The depreciation for each class is calculated based on the current depreciation policies of Hydro One, the current composition of the fleet, and annual forecast additions and deletions. Depreciation costs are expected to be slightly higher in the 2019 bridge year due to a new asset acquisition throught replacement program to support work programs.

2.3 FUEL COST

Fuel cost per class of equipment is calculated based on past history, current market projections, and the current composition of the class. Throughout the year, fuel costs are charged directly to the piece of equipment consuming the fuel.

2.4 EXTERNAL FLEET RENTALS

Due to the seasonal and fluctuating nature of its work program, Hydro One uses externally-owned equipment to meet the peaks in its programs. Using a process similar to that used to cost Hydro One's own fleet, standard rates are calculated and costs are distributed to programs and projects.

2.5 FLEET MANAGEMENT SERVICES

The Fleet Management Services function provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety, and compliance with laws and Ministry regulations, including, but not limited to CSA 225, the *Highway Traffic Act* and the Commercial Vehicle Operator's Registration. Fleet Management Services also ensures that environmental impacts are minimized and line-of-business productivity is optimized by minimizing downtime and travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business by:

- converting the Company's fixed zone model for responding to internal requests to a mobile model, with maintenance garages strategically placed throughout the province to facilitate a more rapid turnaround for vehicle servicing;
- optimizing the number of geographical locations served through implementation of garage hubs;
- reducing equipment downtime and improving equipment utilization;
- providing more competitive and cost-efficient fleet support, enhanced through the procurement of modern maintenance facilities;
- adopting a flexible service delivery model that matches the nomadic and variable work program needs of Hydro One's lines of business with service delivery options that mirror private sector practices (e.g., shift work, extended hours of service and mobile service delivery);
- developing more timely, strategic and cost-efficient processes for equipment procurement and disposal;
- developing a long-range capital replacement program; and
- adopting data collection and information management systems that match the nomadic requirements of the company's business units.

2.6 MAINTENANCE MODEL

Fleet Management Services has developed a balanced maintenance model for mobile service delivery and centralized facilities. This model provides for 45 provincial locations and balances geographical customer requirements, travel time, third-party vendor support, and response time. Mobile/satellite repair units minimize costs organizationally by providing timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance. Services provided to the lines of business meet the rigorous requirements of Fleet Management Services' agreements and are structured as a mobile model to meet work requirements. The inspections and maintenance program is detailed in Section 2.3.3.2 of the Transmission System Plan, which is provided at Exhibit B, Tab 1, Schedule 1 (the "TSP").

2.7 MANAGED SYSTEMS

2.7.1 FLEET MANAGEMENT SYSTEM

The strategic alliance to implement a Fleet Management System (FMS), was developed with Automotive Resources International, now ARI Financial Services Inc. (ARI) in 2003. Hydro One went back to market and awarded a new five- year contract to ARI in 2015. The FMS uses an automated web-based system that utilizes a single credit card for each vehicle to capture operating costs including fuel, parts and repairs. The FMS also incorporates programs to manage contracts, such as tender agreements with Hydro One's vendors, and the system prescribes spending approval guidelines and negotiated discounts. The system measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and compliance on maintenance / inspection requirements.

The benefits of the FMS include:

- improved scheduling of preventative maintenance, reduced repair times, reduced travel time and reduced equipment downtime;
- increased access to a number of vendors for fuel, repairs, and parts, thus minimizing cost and downtime;
- improved cost and efficiency, through carefully-considered procurement strategies and economies of scale, including improved volume discounts for fuel, parts and service;
- a toll-free number for repairs, roadside assistance and towing, and improved reporting and data collection; and
- exposure to best practices for fleet management by similar sector organizations.

The FMS uses a variety of linked programs to manage the data and information for all facets of the business, including internal and external repairs. This takes advantage of both internal and external intelligence and technology.

The maintenance program minimizes expensive repairs and equipment downtime, which results in improved equipment utilization. Both internal and external service providers have access to the appropriate information through state-of-the-art automated management systems, allowing for quality decision-making at all levels of the maintenance program. Examples of the information provided include:

- real-time vehicle history;
- warranty criteria and warranty recovery;
- work and resources scheduling tool;
- pending and overdue work information alert system;

- product information including vendor-specific information;
- repair and safe practices manuals;
- process and policy information;
- invoice and cost-management details;
- monthly and ad-hoc reports; and
- work order management.

2.7.2 TELEMATICS

Fleet Management Services has implemented a fleet telematics system for 4,700 fleet vehicles and transport and work equipment that provides significant enhancements to operator safety, workplace efficiency and reduction of environmental impacts. This project was completed at the end of 2016.

In 2017, Fleet Services has been leveraging the telematics data to institute a framework to define the baseline metrics with respect to equipment utilization and productivity. Analysis of the telematics data allow Hydro One to realize sustainable efficiencies by reducing the Fleet complement by 800 units in 2017 and an additional 200 units in 2018. The data will continue to be analysed throughout the 2019 to 2022 planning period to continuously identify opportunities for costs savings without compromising service quality. Such efficiencies allow Hydro One to maintain service levels without asking customers to pay more. The expected savings and benefits are detailed in Exhibit B, Tab 1, Schedule 1, TSP Section 1.6.

2.8 FLEET COMPLEMENT AND UTILIZATION

Inventory levels are controlled and set by the Hydro One lines of business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations, and utilization targets. Fleet Management Services' 45 facilities support 46 forestry operational centers, over 1,000 distribution stations, 294 transmission stations, and 66 distribution lines operational centers. The fleet complement is detailed in Exhibit B, Tab 1, Schedule 1, TSP Section 2.2.3.2.

As the work program has been increasing, the options to meet increased equipment demand include the purchase of new equipment, rental of additional equipment or increased utilization of existing equipment. The best option is to increase utilization, which minimizes capital investment compared to the option of additional purchases. Simultaneously, it avoids the additional cost of external rentals, which is approximately 45% higher than owned equipment rates based on an internal assessment.

The benefits of improving utilization include:

- decreased long-term capital requirements;
- improved ability to respond to fluctuations in work programs; and
- reduced rental costs, with a correspondingly lower impact on the OM&A budget.

2.9 FLEET MANAGEMENT SERVICES BUDGET

Fleet Management Services' annual budget is developed and managed based on the all-in costs of operating the fleet and the following criteria:

- historical and forecast fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, and external rentals;
- historical cost and mechanical fitness evaluations;
- work program forecasts provided by the lines of business;
- estimates provided by internal and external providers;
- requirements of the capital/vehicle replacement program; and
- projected escalators.

COSTING OF WORK: MATERIALS SURCHARGE

1. OVERVIEW: MATERIAL SURCHARGE RATE

Hydro One applies a standard material surcharge rate, which captures applicable supply chain procurement costs, to material costs. Material costs charged to a project or program are based on the issue cost, which is either the "moving average price" or the direct-shipped purchase order price. On a monthly basis, total monthly material charges are surcharged with a fixed percentage cost to recover costs associated with purchasing, transportation and inventory management. The percentages range from 7% to 18%, depending on work program service requirements. The percentages are derived by dividing the costs assigned to each work program or project for these activities (based on an annual assessment of the program's consumption of these services) by the annual forecast of purchased material.

The costs recovered in the materials surcharge are as follows:

- Hydro One Costs - management, demand planning, warehousing and transportation of material, rental tools and investment recovery (comprising approximately 68% of the total costs); and
- Inergi LP ("Inergi") Contract Costs – procurement (comprising approximately 32% of the total costs).

2. SUPPLY CHAIN SERVICES

This section describes the budgeted cost levels and components of supply chain services.

Table 1: Supply Chain Services ($ Million)*

	Historic				Bridge	Test		
	2015	**2016**	**2017**	**2018**	**2019****	**2020**	**2021**	**2022**
Total	38.5	35.4	33.2	30.2	35.9	36.2	40.6	28.3

** Central Tools Services (CTS) not included in table 1, see section 2.1 below*

*** Accounts Payable will be recovered as part of the Material Surcharge as of 2019, cost are approximately $1M annually, included in table 1*

As Table 1 shows, the forecast 2019 costs for supply chain services are expected to be $35.9 million. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials, demand planning, inspection services, transportation, inventory management, and investment recovery of disposed assets. The components of supply chain services performed by Inergi include spot buying of materials and services, purchasing services (i.e. purchase order changes), contract management and accounts payable.

In early 2017 Supply Chain set a strategic plan to improve the service and value it delivers to its internal customers. To meet its strategic plan, Supply Chain is transforming its organization to focus on providing exceptional service and centrally aligned category management and operational procurement teams to more effectively manage critical categories of spend. The strategic plan has introduced new best in class technology, process changes and included an organizational transformation which began in 2018:

- New Technology
    - Ariba - Online e-Sourcing, central contract repository, spend analysis and catalogues; and
    - Fieldglass - Online procurement of contingent workforce, external services and projects.
- Process Changes
    - Category Management - Category Teams will be responsible for:
        - Internal and market analysis;
        - Category strategy development and execution; and
        - Supplier performance management.
- Organizational Transformation
    - In-sourcing of the following services in 2018 and 2019:
        - Tactical Sourcing;
        - Inspection Services; and
        - Transportation Services.

As a result, Supply Chain's strategic direction is to stagger resourcing and ramp-up staff commencing in 2018 through to the end of 2021 to align with the expiry of the outsourcing contract. Improvements in people, process and technology will enable Hydro One to improve its ability to drive increased savings and operating cost levels.

Supply chain costs are forecast to decrease in 2022 onwards, subject to Hydro One's work programs. The efficiencies Supply Chain Services will realize reflects Hydro One's commitment company-wide, to operational effectiveness as it develops an investment plan that aligns customer needs, asset needs and rate impact.

2.1 CENTRAL TOOL SERVICES (CTS)

Table 2: Central Tool Services ($ Million)*

	Historic				Bridge	Test		
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Total	2.9	2.9	2.9	2.7	2.9	2.9	2.9	2.9

**CTS not included in table 1 above*

In Q1 2017, CTS was moved under the Supply Chain organization. As of 2018, CTS' total budget was contained within Supply Chain's budget.

CTS provides tool rentals and tool repair/maintenance services in support of construction and maintenance programs. CTS manages safety recalls and inspections of designated tools as well as performs calibration of specific tools and equipment. The group also identifies, procures and warehouses new tools.

2.2 SOURCING OF MATERIALS AND SERVICES

The sourcing of materials and services includes the following:

- Demand Management and Procurement – market intelligence with respect to commodities, processing purchase transactions, and inspecting and expediting services to ensure delivery of contract commitments; and
- Sourcing and Vendor Management – services to support sourcing all commodities and services which include managing the size and composition of the vendor base and resolving issues.

Hydro One manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's process includes spending analysis, market analysis, development of a sourcing strategy, negotiation, award, and contract management.

2.3 INSPECTION SERVICES

Hydro One provides timely inspection services to assure that products are manufactured in accordance to specifications established by Hydro One, and tracks costs and schedules on a product and project basis. Inspectors perform vendor plant audits, including emergency and ad-hoc inspections to ensure conformance to contract specifications, as well as coordinate and monitor non-conformance resolutions and performance issues with vendors' plants and operations.

2.4 STORAGE AND DISTRIBUTION OF MATERIALS – WAREHOUSING

Hydro One's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This warehouse services the operations and maintenance organizations that are further serviced through 81 field service centres, 29 station locations and eight construction sites. The field staff are responsible for receiving shipments and for storing and ordering material. Deliveries to the service centres are contracted to a third-party transportation carrier.

The intent of a consolidated warehouse operation is to realize efficiencies through focusing on activities such as:

- minimizing and/or consolidating order quantities to leverage discounts with vendors;
- consolidating freight to each location to minimize the frequency and cost of deliveries;
- managing and coordinating the delivery of materials on the scheduled delivery date to service centres to ensure that field operations receives the right materials at the right time; and
- improving receipting efficiency by integrating with the contracted transportation company to provide visibility into the supply chain and scheduling the inbound shipment.

2.5 TRANSPORTATION

Hydro One manages its inbound and outbound transportation of materials through contracts with third parties. In 2017, Hydro One exercised a three-year renewal option on its transportation contract for material delivery in and out of the central warehouse. In some instances, material is shipped directly from the supplier to the job site.

2.6 INVESTMENT RECOVERY

The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range of $3.8 million to $4.2 million per year, and primarily involves vehicle sales and scrap metal. Hydro One continues to focus on extracting the maximum value possible from the sale of these assets. Table 2 summarizes the sale of assets through the Investment Recovery Program.

Table 3: Sales of Assets through Investment Recovery Program ($ Millions)

Type of Sale	Recovery 2015	Recovery 2016	Recovery 2017	Recovery 2018
Vehicle Sales	2.7	1.9	3.3*	4.5*
Scrap Metal	1.1	1.1	0.9	1.5
Total	**3.8**	**3.0**	**4.2**	**6.0**

**2017 and 2018 spike in vehicle sales due to Fleet right-sizing initiative.*

2.7 SUPPLY CHAIN POLICIES AND PROCEDURES

Hydro One acquires materials and services through a process that drives value for money, delivers transparency to its internal customers and builds mutually valuable relationships with key suppliers. Details on Hydro One's procurement policy are provided in Exhibit F, Tab 3, Schedule 2.

2.8 COST SAVINGS FROM STRATEGIC SOURCING

Strategic sourcing is a major focus for Hydro One, as the company emphasizes cost control and security of supply, while markets remain volatile and demand in the global utility sector increases. Savings are realized in the purchase of major equipment commodities and services, for example, power transformers, and circuit breakers.

Strategic sourcing results vary between commodities and are largely a result of increased leverage and reduction of total life-cycle cost for materials and services.

The main benefits of sourcing strategies are listed below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;

- Cost reduction by increased leverage of company-wide expenditures – Purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. An added benefit is that this approach eliminates the need to tender and purchase as requirements surface;
- Reduced total life-cycle cost for materials and services – When purchasing equipment, all aspects are identified to ensure that Hydro One acquires maximum value for the life-cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and inventory requirements, etc. are evaluated to determine where greater efficiencies may be realized;
- Improved security of supply through longer-term agreements – To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One achieves best value; and
- Improved and/or consistent quality of material and services.

Following the 2015 Initial Public Offering ("IPO") of Hydro One Limited shares, Hydro One identified opportunities for cost savings and productivity improvements. Its planned enhancements to sourcing approaches are detailed in Section 1.6 of the Transmission System Plan (the "TSP") provided as Exhibit B, Tab 1, Schedule 1.

2.9 RECENT IMPROVEMENTS IN SUPPLY CHAIN SERVICES

Hydro One continues to advance its procurement practices. This section lists some improvement initiatives which include:

- Category Management - Transforming its organization to focus its capabilities on distinct service Supply Chains and centrally align category management and operational procurement teams to more effectively manage critical categories of

- spend by aligning with LOB objectives, creating dynamic strategic sourcing strategies using market intelligence, maximizing value impact, and enabling cross-organization solutions;
- Ariba and Fieldglass - Provide access to the largest supplier network and create a centralized, secure contract repository; provide greater management and control over service based procurement;
- Spend Visibility - Combines procurement data from SAP into a simple drag and drop tool that can be used to create custom reports and visuals;
- Supplier Performance and Relationship Management - will drive excellence in performance, enhance relationships and develop continuous improvement strategies with Hydro One's suppliers. The program consists of two segments:
    - Supplier Performance Management (SPM) where the supplier's performance will be measured through key performance indicators to improve productivity, mitigate risk and enhance contract compliance
    - Once SPM is successful, Hydro One implement Supplier Relationship Management (SRM) which will engage the top performing suppliers in mutually beneficial, continuous improvement and development projects;
- Cost Intelligence - Leverage external market data to drive down costs by using historical and forecast cost driver to assess bids, negotiate with vendors and manage price escalations; and
- ISNetworld - Performs online pre-qualification and maintenance of vendor master data for health and safety, insurance and WSIB.