RATE BASE

1.0 INTRODUCTION

This exhibit provides the forecast of Hydro One Distribution's rate base for the test years 2015 to 2019 and provides a detailed description of each of the components of rate base.

In accordance with the 2006 Electricity Distribution Rate Handbook ("Handbook"), the rate base underlying each of the test years' revenue requirement 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 supplies inventory.

2.0 UTILITY RATE BASE

Utility rate base for the distribution system for the test year is filed at Exhibit D2, Tab 1, Schedule 1. The calculation of Net Utility Plant is provided at Exhibit D2, Tab 3, Schedule 1 and 2.

Hydro One Distribution's forecast rate base for the test years 2015 to 2019 is shown in Table 1.

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

Table 1

Distribution Rate Base

($ Millions)

DESCRIPTION	**Test Years**				
	2015	**2016**	**2017**	**2018**	**2019**
Mid Year Gross Plant	10,099.9	10,650.8	11,239.1	11,849.4	12,397.4
Mid Year Accumulated Depreciation	(3,802.9)	(4,046.7)	(4,311.7)	(4,572.2)	(4,792.5)
Mid Year Net Plant	6,297.0	6,604.1	6,927.4	7,277.2	7,604.9
Cash Working Capital	249.9	253.6	257.3	257.2	257.7
Materials and Supplies Inventory	6.5	6.6	6.8	6.9	7.0
Distribution Rate Base	6,553.3	6,864.4	7,191.4	7,541.3	7,869.6

The mid-year gross plant balance reflects the capital expenditure programs forecast for the bridge and test years. These programs are described in detail in the company's written evidence at Exhibits D1, Tab 3, Schedules 1 through 5 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedule 2. The justification for capital projects in excess of $1 million are provided in Exhibit D2, Tab 2, Schedule 3.

The gross plant component of the 2011 rate base approved in the EB-2009-0096 was $7,603.4 million. The 2015 net plant of $10,099.9 million is $2,496.5 million or 32.8% higher than that of the last approved. The growth in gross plant primarily reflects the in-service additions made to Hydro One Distribution rate base during the IRM period from 2012 to 2014 and amounts previously recorded as regulatory assets.

As of January 1, 2015, $564.9 million of Smart Meter, Smart Grid and Distributed Generation gross fixed assets previously recorded as regulatory assets and tracked in deferral accounts are all transferred into Hydro One Distribution rate base with no half year rule and are included as part of this application. The only exclusion from the rate base calculation is the provincially funded portion of the Distributed Generation assets completed by Hydro One Distribution. Continuity schedules are provided at Exhibit D2, Tab 3.

Table 2 shows the historical and bridge year continuity of core fixed assets, excluding the in-service addtions of the regulatory assets tracked in deferral accounts from 2010 to 2014.

Table 2

Continuity of Fixed Assets Summary - Core Rate Base

($ Million)

Description	**Historical Years**				**Bridge Year**
	2010	**2011**	**2012**	**2013**	**2014**
Opening Gross Asset Balance	6,966.7	7,368.0	7,773.4	8,149.1	8,726.9
In-Service Additions	438.5	452.5	414.2	687.2	554.6
Retirements	(19.9)	(38.0)	(26.9)	(93.8)	(28.4)
Sales	(8.9)	(10.8)	(10.3)	(15.6)	-
Transfers	(8.4)	1.6	(1.3)	0.0	-
Closing Gross Asset Balance	7,368.0	7,773.4	8,149.1	8,726.9	9,253.1
Less Future Use Land	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Gross Assets for Mid Year Rate Base	7,367.7	7,773.1	8,148.8	8,726.6	9,252.8

Table 3 shows the historical and bridge year continuity of fixed assets driven by the in-service addtions of the regulatory assets from 2010 to 2014. Smart Meter, Smart Grid and Distributed Generation gross fixed assets previously recorded as regulatory assets and tracked in deferral/variance accounts are not included in the rate base until January 1, 2015. Hydro One is seeking the disposition of these deferral/variance accounts in this application. The details of the Smart Meter, Smart Grid and Distributed Generation projects and spends from 2010 to 2014 are filed at Exhibit D1, Tab 1, Schedule 2, Attachment 2 to 4. The continuity schedules of the regulatory accounts associated with these projects are filed at Exhibit F1, Tab 1, Schedule 3.

Table 3
Continuity of Fixed Assets Summary – Regulatory Assets
($ Million)

Description	**Historical Years**				**Bridge Year**
	2010	**2011**	**2012**	**2013**	**2014**
Opening Gross Asset Balance	160.5	271.0	347.1	487.1	529.2
In-Service Additions	110.5	76.2	140.0	42.1	83.0
Retirements	-	-	-	-	-
Sales	-	-	-	-	-
Transfers	-	-	-	-	-
Closing Gross Asset Balance	271.0	347.1	487.1	529.2	612.2
Less Provincial Funded Assets (a)	(0.4)	(4.2)	(7.0)	(14.2)	(47.4)
Gross Assets for Rate Base	270.5	342.9	480.1	515.0	**564.9**

Table 4 reflects the proper regulatory treatment of the inclusion of the Smart Meter, Smart Grid and Distributed Generation assets into Hydro One Distribution's rate base in 2015 or at December 31, 2014. Please note that the continuity of fixed asset schedules filed at Exhibit D2, Tab 3, Schedule 1 to 3 reflect the total fixed asset activity including both the core and regulatory assets as if the regulatory assets were placed in service and included in the rate base in the same year. Both presentations result in the same fixed asset forecast balances for the test years.

Table 4

Continuity of Total Fixed Assets Summary

($ Million)

Description	**Historical Years**				**Bridge Year**
	2010	**2011**	**2012**	**2013**	**2014**
Opening Core Gross Asset Balance	6,966.7	7,368.0	7,773.4	8,149.2	8,726.9
In-Service Additions	438.5	452.5	414.2	687.2	554.6
Retirements	(19.9)	(38.0)	(26.9)	(93.8)	(28.4)
Sales	(8.9)	(10.8)	(10.3)	(15.6)	-
Transfers	(8.4)	1.6	(1.3)	-	-
Closing Core Gross Asset Balance	7,368.0	7,773.4	8,149.2	8,726.9	9,253.1
Include Deferral Accounts	-	-	-	-	***612.3***
Closing Total Gross Asset Balance	7,368.0	7,773.4	8,149.2	8,726.9	9,865.4
Less Provincial Funded Assets	-	-	-	-	***(47.4)***
Less Future Use Land	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Closing Gross Assets for Rate Base	7,367.7	7,773.1	8,148.9	8,726.6	9,817.7

Table 5 provides the forecast continuity of fixed assets for the test years.

Table 5
Continuity of Total Fixed Assets Forecast
($ Million)

Description	Test Years				
	2015	**2016**	**2017**	**2018**	**2019**
Opening Gross Asset Balance	**9,865.4**	**10,459.9**	**11,021.6**	**11,676.8**	**12,266.6**
In-Service Additions	656.6	621.8	696.0	681.4	660.9
Retirements	(62.1)	(60.1)	(40.8)	(91.6)	(140.7)
Sales	-	-	-	-	-
Transfers	-	-	-	-	-
Closing Gross Asset Balance	**10,459.9**	**11,021.6**	**11,676.8**	**12,266.6**	**12,786.8**
Less Provincial Funded Assets (a)	(77.5)	(101.9)	(117.6)	(126.4)	(131.5)
Less Future Use Land	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Gross Assets for Mid Year Rate Base	**10,382.1**	**10,919.4**	**11,558.9**	**12,139.9**	**12,654.9**
Mid Year Gross Asset Balance (b)	10,099.9	10,650.8	11,239.1	11,849.4	12,397.4

Notes:
a) Provincially funded Distributed Generation assets are captured in a deferral account and excluded for the purposes of calculating core rate base for all historical, bridge and test years.
b) Mid year gross asset balance is calculated only for the test years.

In-service additions reflect the placing in service of Hydro One Distribution's capital programs and are discussed in Exhibit D1, Tab 1, Schedule 2. These programs are described in detail at Exhibit D1, Tab 3, Schedules 1 through 9.

The retirement of assets over the test years include distribution plant equipment, meters and computer software. In 2018 and 2019, phase 1 of Hydro One's SAP Cornerstone project becomes fully depreciated and thus retired.

Transfers over the period reflect movement between the strategic spares inventory and fixed assets.

3.0 WORKING CAPITAL

In 2013 Hydro One Distribution 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 2015 through 2019 test years are incorporated.

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

- the forecast of OM&A,
- the retail cost of power,
- capital and income taxes,
- the net lead-lag days determined.

The other component of Working Capital is materials and supplies inventory.

The application of the methodology from the lead lag study results in a net cash working capital requirement including the impact of HST are shown in Table 6. The 2015 test year cash working capital allowance has been calculated to be $237.1M which is a $57.8M decrease from the 2011 cash working capital allowance of $294.9M approved by the Board in EB-2009-0096. Details of the Working Capital requirements for Hydro One

Distribution are filed in Exhibit D1, Tab 1, Schedule 3 and Exhibit D2, Tab 4, Schedule 1 for the test years.

Table 6

Cash Working Capital Allowance

($ Million)

	Test Years				
	2015	**2016**	**2017**	**2018**	**2019**
Cash Working Capital	237.1	239.7	241.1	240.0	241.0

IN-SERVICE CAPITAL ADDITIONS

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 Distribution's customers. It is important to note that, in aggregate, the values for in-service additions will differ from capital expenditures in any given year. This difference arises from the fact that work and associated capital expenditures for many projects span multiple years, at the end of which time the projects are declared "in-service" and the associated accumulations of those capital expenditures are recognized as "in-service additions". As well, some capital projects can come into service in stages.

Table 1 shows the actual in-service capital additions for historical years 2010 to 2013, and forecast in-service additions for the bridge year 2014. The table also shows the variance between the actual in-service amounts and those approved by the Board in Hydro One Distribution's 2010 and 2011 Cost of Serivce application, EB-2009-0096. For comparison purposes, the in-service capital additions in Table 1 include only those projects driven by the Company's core work programs and exclude the additions driven by investments related to Smart Meter, Smart Grid and Distributed Generation which have been recorded in variance accounts as regulatory assets since January 1, 2010 as per the Board's Decision in EB-2009-0096. The exclusion of the regulatory assets from in service was due to the uncertain nature of the investments as most of these projects are driven by government intiatives, customer requests and new technologies.

Table 1
In-Service Capital Additions 2010-2014 ($ M): OEB Approved and Actual/Forecast

	Historic								Bridge
	2010			2011			2012	2013	2014
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	Actual		Forecast
Sustaining	175.8	171.6	-4.2	195.5	203.3	7.8	195.6	277.1	286.6
Development	166.1	171.6	5.6	168.3	159.0	-9.3	141.9	185.3	155.4
Operations	6.8	2.3	-4.5	9.0	0.8	-8.2	2.3	1.4	4.0
Common & Other	114.5*	93.0	-21.6	50.3*	89.5	39.2	74.4	223.4	108.6
Total	**463.2**	**438.5**	**-24.7**	**423.1**	**452.5**	**29.4**	**414.2**	**687.2**	**554.6**

*The envelop reduction to capital expenditure in 2010 and 2011, which leads to a reduction in in-service additions, ordered by the Board in its April 10, 2010 Decision in EB-2009-0096 is reflected in the Common & Other Capital.

The 2010 in-service additions are $24.7 million lower than the OEB approved level of $463.2 million and the 2011 in-service additions are $29.4 million higher than the approved level of $423.1 million. The level of in-service additions over the two years is very close to Board approved levels but the timing was slightly shifted from the original forecast.

Primary factors behind the 2010 in-service additions being $24.7 million lower than the Board approved level were lower than planned additions for transport and work equipment (TWE) and real estate. In the Board's Decision in EB-2009-0096, it was suggested that lower spending in these two areas would help to meet the reductions in Capital spending ordered by the Board. The lower spending and in-service additions were primarily related to the slower pace of renewable distributed generation connections than forecast in the EB-2009-0096 application.

Primary factors behind the 2011 in-service additions being $29.4 million higher than the Board approved level were higher spending and in-service on storm damage and repair, higher in-service on system capability reinforcement to meet system requirements and higher in-service for the Cornerstone project.

The Smart Meter, Smart Grid and Distributed Generation in-service capital additions excluded in Table 1 are added to Table 2. This application is seeking Board approval to place the Smart Meter, Smart Grid and Distributed Generation assets into ongoing operations and rate base starting in 2015, consistent with the Board's guidance in its Renewed Regulatory Framework that these investments are considered an intergral part of the utility's investment plan. For regulatory purposes, there is no longer the need for a Green Energy Plan to make a distinction between these investments and the more traditional investments undertaken by distributors. The actual and forecast amounts in Table 2 for the historical and bridge years are different from those shown in Table 1 as the regulatory assets are included to show a more realistic view of these years for comparison with the test years.

Table 2

In-Service Capital Additions 2010-2019 ($ M):

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	Actual				**Forecast**					
Sustaining	283.3	275.1	259.6	296.6	306.9	294.2	311.9	335.7	354.2	365.2
Development	179.0	165.7	145.0	194.1	196.0	218.9	200.8	211.2	217.6	190.7
Operations	2.3	0.8	2.3	1.4	4.0	11.1	8.1	16.4	6.8	1.4
Customer Service	(0.0)	-	72.6	13.9	22.1	46.0	20.6	27.7	20.4	20.0
Common & Other	84.4	87.1	74.7	223.4	108.6	86.4	80.5	105.0	82.4	83.7
Total	549.0	528.7	554.2	729.3	637.6	656.6	621.8	696.0	681.4	660.9

Note: Amounts in 2010 to 2014 include regulatory assets associated with Smart Meter, Smart Grid and Distributed Generation, details for which are provided at Exhibit F1, Tab 1, Schedule 3.

The major drivers of the in-service levels requested in 2015 through 2019 within the sustainment, development and operation work programs include the following:

- new connections and upgrades;

- troubled calls and storm damage;
- the replacement of assets at the end of their expected service lives;
- system capability reinforcements;
- joint use and relocation capital projects;
- ending the Smart Grid pilot project and beginning deployment of Smart Grid;
- line improvement capital projects to ensure supply reliability to distribution customers.

Hydro One Distribution is expecting to achieve the levels of in-service capital additions being sought for 2015 through 2019 by utilizing a mix of internal and external resources, including outsourcing. Please refer to the Work Execution Strategy in Exhibit A, Tab 17, Schedule 6 for a further explanantion of how Hydro One Distribution plans to accomplish the work program.

Hydro One Distribution's in-service capital additions in 2013, including the regulatory assets were $729.3 million. This is a significant increase from the 2012 level of $554.2 million. The increase results from the inclusion of assets treated under the Incremental Capital Module ("ICM") in 2013 including the completion of the Customer Information System (CIS) replacement project. The ICM was approved in EB-2012-0136. A detailed description of the ICM projects is provided in Attachment 1 of this exhibit.

WORKING CAPITAL (LEAD-LAG STUDY)

1.0 INTRODUCTION

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 the OEB's EB-2009-0096 Decision with Reasons, the OEB accepted the results of the Navigant lead-lag study. In 2013, Hydro One commissioned Navigant to conduct an updated lead-lag study which is included in Exhibit D1, Tab 1, Schedule 3, Attachment A (entitled Working Capital Requirements of Hydro One Networks' Distribution Business – dated December 3, 2013). The amounts summaried in the following tables in this exhibit have been updated since the study was completed by Navigant in 2013 to reflect the 2013 actual results, and the flow through impacts during the test years.

2.0 SUMMARY

Hydro One Distribution's net cash working capital requirement for the 2015 test year is $249.9 million or 7.4% of OM&A ($564.3M) and Cost of Power expenses ($2,816.2M). Applying the same formula the remaining test years are: 2016 - 7.4%; 2017 - 7.4%; 2018 - 7.5% and 2019 - 7.5%. Table 1 summarizes the net cash working capital requirements determined by using the lead/lag days from the Navigant study filed in Exhibit D1, Tab 1, Schedule 3, Attachment 1 to reflect the 2015 and 2019 test year revenues, expenses and HST amounts (Table 2).

The methodology used to determine the net working cash 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:

- has considered the most important elements of revenue lags, including the service, billing and collection lags;
- includes the most important elements of expense leads such as payroll and benefits, operations, maintenance, administration expenses, and taxes, including property taxes; and
- takes the major cost elements into consideration in calculating the net cash working capital.

Table 1

Distribution Net Cash Working Capital Requirement

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

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead Days)**	**2015 Test Year**	**2016 Test Year**	**2017 Test Year**	**2018 Test Year**	**2019 Test Year**
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Expenses								
Cost of Power	52.25	32.74	19.51	2816.2	2831.3	2853.9	2842.2	2831.6
OM&A	52.25	27.11	25.14	564.3	610.2	614.0	603.9	600.0
Removal Costs	52.25	16.51	35.74	54.5	57.0	60.4	63.3	65.8
Environmental Costs	52.25	40.98	11.27	14.2	22.0	22.4	22.0	21.6
Interest on Long-Term Debt	52.25	8.93	43.32	179.8	191.3	203.0	218.4	236.9
PILS	52.25	128.37	(76.12)	52.5	60.5	63.0	65.4	69.5
Total				**3681.4**	**3772.3**	**3816.6**	**3815.1**	**3825.5**
HST				991.1	1012.1	1025.9	1026.8	1030.7
Total Amounts Paid/Accrued				**4672.6**	**4784.4**	**4842.6**	**4841.9**	**4856.1**
<u>Working Capital Required</u> (Calculations based on above values, for each expense category, calculated using the following formula: For Test Years 2015 to 2019 (Col (D)*Col (C)/365))								
Cost of Power				150.5	150.9	152.5	151.9	151.4
OM&A				38.9	41.9	42.3	41.6	41.3
Removal Costs				5.3	5.6	5.9	6.2	6.4
Environmental Costs				0.4	0.7	0.7	0.7	0.7
Interest on Long-Term Debt				21.3	22.6	24.1	25.9	28.1
Income & Capital Tax				(11.0)	(12.6)	(13.1)	(13.6)	(14.5)
Total				205.6	209.1	212.4	212.7	213.4
HST (see Table 2)				44.3	44.5	44.9	44.5	44.3
Net Working Capital Required				**249.9**	**253.6**	**257.3**	**257.2**	**257.7**

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

	HST Lead Time (Days)	**Working Capital Factor**	**2015 Test Year**	**2016 Test Year**	**2017 Test Year**	**2018 Test Year**	**2019 Test Year**
Revenue (external)	(7.13)	-2.0%	(10.7)	(11.0)	(11.3)	(11.3)	(11.4)
OM&A	42.92	11.8%	3.2	3.5	3.5	3.5	3.4
Cost of power	45.92	12.6%	46.1	46.2	46.7	46.5	46.3
Removal costs	44.30	12.1%	0.1	0.1	0.1	0.1	0.1
Environmental costs	44.30	12.1%	0.1	0.1	0.1	0.1	0.1
Capital expenditures	44.30	12.1%	5.6	5.6	5.7	5.6	5.8
Total			**44.3**	**44.5**	**44.9**	**44.5**	**44.3**

Refer to page 11 of Attachment 1 for more detail on the Distribution HST Cash Working Capital Requirement.

MATERIALS AND SUPPLIES INVENTORY

1.0 STRATEGY

Hydro One Distribution 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 2010 to 2013 inventory levels continue to reflect the impact of the increasing work programs, the increasing distribution asset base, offset by initiatives to manage inventory growth. Inventory in service centres was reduced by approximately $1M in late 2012. A description of Hydro One Distribution’s Supply Chain and on-going cost containment initiatives are described in Exhibit C1, Tab 4, Schedule 1, Section 4.0.

2.0 INVENTORY

As of December 31, 2012 Hydro One Distribution carried a total year-end inventory valued at $37.2 million. Table 1 provides the actual inventory levels for 2010 to 2013. The inventory forecast levels for the bridge year 2014 and test years 2015 to 2019 inclusive are included in the table for both the year-end balances and mid year balances.

Table 1

Inventory Levels (Distribution) 2010 – 2019 ($ Million)

Year end Balances	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Materials and Supplies	5.0	4.4	6.5	6.3	6.4	6.6	6.7	6.8	7.0	7.1
Future Use Inventory	31.3	31.7	30.7	29.0	29.6	30.2	30.8	31.4	32.0	32.7
Total Inventory	36.3	36.1	37.2	35.3	36.0	36.7	37.5	38.2	39.0	39.8

Mid Year Balances	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Materials and Supplies	5.4	4.7	5.5	6.4	6.4	6.5	6.6	6.8	6.9	7.0
Future Use Inventory	31.0	31.5	31.2	29.9	29.3	29.9	30.5	31.1	31.7	32.3
Total Inventory	36.4	36.2	36.7	36.3	35.7	36.4	37.1	37.8	38.6	39.4

***** Inventory allocation is based on a 2 ½ year trend of actual goods out of inventory. Blue page revision reflects updated allocations.

Over the 2010 to 2012 period, the average annual inventory levels have increased at approximately 0.3% per year, while the forecasted inventory levels from 2014 to 2019 are shown to be increasing by approximately 0.2% annually. This increase is attributed to:

- a large percentage of the distribution asset base entering its mid-life to end-of-life age demographic, where the need for additional inventory is required to support possible increased failure rates;
- the growth in the distribution work program to maintain an aging infrastructure;
- maintain compliance with the Regulatory requirement to connect a minimum of 90% of new customers within 5 days;
- Vendor lead time/mitigation of “stock-outs”; and
- Storm/trouble response.

2.1 Planned Levels of Inventories

Most of Hydro One Distribution’s materials and supplies are sourced from inventoried stock. The basis of forecasting inventory levels assumes that historical inventory patterns are maintained and modified to reflect planned work program changes.

Materials and Supplies for major distribution projects are usually shipped directly to the project sites and are not included in the planned inventory levels.

Inventories are held for the maintenance of existing assets and new development activities (i.e. new customer connections, etc.). Inventory primarily includes component parts – lines, poles, wire and cable, hardware, switches, transformers, protective devices, metering systems, circuit breakers, contacts, pallet switches, insulators etc.

2.2 Monthly Inventory Levels 2010 to 2013

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 2010 through 2013 are shown in Table 2 below.

Table 2
Historical Monthly Inventory Levels 2010 – 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	36.0	36.4	37.7	35.5	36.4	36.7	34.2	33.0	33.0	33.2	33.5	36.3
2011	35.7	36.8	37.4	36.9	36.3	36.0	36.0	35.3	34.7	35.2	34.4	36.1
2012	36.7	38.2	39.0	39.8	37.9	38.1	37.7	38.6	37.9	37.8	37.1	37.2
2013	38.3	38.2	39	39.8	37.9	38.1	37.7	36.9	36.6	36.9	36.5	35.3

The inventories of consumable materials are seasonal in nature, driven primarily by storm season and new connections. Monthly inventories are ramped up to meet these increased needs. For the most part, the trend indicates lower inventories at the beginning and end of each year, with an increase during the spring and early summer. The spring and summer timeframe increase is due to the beginning of construction season and the building of storm inventory for distribution transformers and related hardware. The drop at the end of the year is due to the consumption of stock for planned, unplanned emergencies and storm response efforts.

SUMMARY OF CAPITAL EXPENDITURES

1.0 SUMMARY OF CAPITAL EXPENDITURES

The requested capital expenditures result from the rigorous business planning and work prioritization processes described in detail at Exhibit A, Tab 17, Schedules 1 through 7. These processes reflect a risk-based decision-making approach to ensure appropriate and cost-effective investments.

The capital expenditures in this Application represent investments that will ultimately become in-service capital assets supporting the Hydro One Distribution business. Specifically, these expenditures include:

a) planning, purchase, construction and commissioning of specific assets providing future economic benefits;
b) additions to or replacement of specific assets; and
c) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

The capital programs address Hydro One Distribution's integrated set of needs to meet its objectives of: public and employee safety; compliance with regulatory and environmental requirements (e.g. Distribution System Code and PCB regulations); managing service quality and reliability; addressing customers' needs; and meeting system growth and asset end-of-life requirements as well as meeting the Board's objectives of its Renewed Regulatory Framework.

Hydro One Distribution's capital expenditures are grouped into five investment categories: Sustaining, Development, Operations, Customer Service, and Common Corporate Costs and Other Capital the latter of which includes expenditures for information technology, transport and service equipment, and facilities and real estate. Table 1 provides a summary of Hydro One Distribution’s capital expenditures for the historical, bridge and test years.

TABLE 1

Summary of Distribution Capital Expenditures ($ Million)

Description	**Historic**						**Bridge**	**Test**				
	2010	**2010 Approved**	**2011**	**2011 Approved**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sustaining	314.0	289.0	274.2	246.9	261.8	323.2	286.4	308.2	335.2	359.7	380.4	383.5
Development	162.9	185.0	157.1	202.5	185.9	192.1	200.2	223.3	206.3	207.7	183.5	199.1
Operations	1.2	8.0	1.3	11.2	2.7	3.6	5.1	9.4	18.8	7.0	7.0	4.2
Customer Service Capital	18.4	21.0	30.1	49.9	43.1	6.4	22.9	22.6	9.9	3.9	0.0	0.0
Corporate Common Costs & Other Capital	93.2	114.0*	133.0	64.6*	142.5	111.7	109.9	85.4	84.5	83.1	84.2	82.3
TOTAL	**589.7**	**617.0**	**595.7**	**575.1**	**636.0**	**637.0**	**624.5**	**648.9**	**654.7**	**661.4**	**655.1**	**669.1**

*The envelope reduction to Capital from the OEB Decision was not spread across the work program areas but was included in Other Capital

The 2010 and 2011 Approved amounts shown in Table 1 include capital work approved for inclusion in the base revenue requirement and capital work recorded in variance accounts (Smart Meter, Smart Grid and Distributed Generation). This work is considered business as usual in the test years, consistent with the direction provided by the Board in its Renrewed Regulatory Framework, thus it is also shown in the historic and bridge years to provide a better comparison of work over the years. Capital spending in 2010 was below the Board approved level due to lower spending on new connections, operations, TWE and facilities. Capital spending in 2011 was above the Board approved level due to higher spending on distribution stations, meters and Cornerstone.

Total net capital expenditures for 2015 are increasing by $24.4 million or 4% over the projected 2014 bridge year expenditures and remain relatively flat, fluctuating around the $650 million spend level throughout the test years until 2019. Contributing to the increase in net capital expenditures over the test years is a growth in Sustaining Capital to address concerns with the deteriorating condition of wood poles and to address station assets that have reached the end of their expected service life. Development Capital expenditures increase in 2015 and 2016 largely due to investments in system capability reinforcement and investments to facilitate an increasing number of customer connections and upgrades. The increase in Operations Capital in 2016 is to fund the development of the Backup Control Centre facility. Overall, the increases in Sustaining, Development and Operations Capital are offset by the decrease in Customer Service and Corporate Common Costs spending. The decrease in these areas is mainly attributed to the completion of the CIS implementation in 2013, other Cornerstone initiatives in 2014 and the Smart Grid pilot project in 2017.

2.0 SUSTAINING

The Sustaining Capital expenditures include the costs for investments required to ensure that existing distribution system facilities function as originally designed. Hydro One Distribution manages its distribution sustaining program within three program categories, namely stations, lines, and meters, telecom and control. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 2.

3.0 DEVELOPMENT

The Development Capital expenditures consist of the investments required to serve new load and generation customers and meet the needs of existing customers. Development Capital includes programs for load customer connections, system capacity reinforcements, and distribution generation connection. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS

Operations Capital represents investments in infrastructure required to sustain the Distribution Operations function which is operated from Hydro One's Ontario Grid Control Centre. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 4.

5.0 CUSTOMER SEVICE CAPITAL

Customer Service Capital provides funding for the Smart Grid Pilot project. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 5.

6.0 CORPORATE COMMON COSTS & OTHER CAPITAL

Corporate Common Costs & Other Capital consists of the sustainment and enhancement of existing equipment and infrastructure, including information technology, transport and work equipment and service equipment, and facilities and real estate. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedules 6 to 9.

SUSTAINING CAPITAL

1.0 INTRODUCTION

Distribution sustaining capital represents expenditures required to replace or refurbish existing components of the distribution system to ensure they will continue to function as originally designed. Opportunities to install distribution automation devices are considered and installed, where prudent, in order to modernize the system and better serve customer expectations in line with the Renewed Regulatory Framework for Electricity Distributors direction for smart grid investments.

Hydro One Distribution manages the sustaining capital programs by dividing the expenditures into the following three categories:

- Stations – Expenditures that fund the work required to replace or refurbish distribution stations or individual pieces of equipment within distribution stations;
- Lines – Expenditures that fund the work required to replace, refurbish or relocate line sections or individual components that comprise line sections; and
- Meters – Expenditures that fund the work required to upgrade and sustain the retail meter inventory.

Sustaining capital investments are intended to maintain the viability of the distribution system, ensure public and employee safety, ensure operational effectiveness by providing an acceptable level of reliability, deliver on customer commitments to demonstrate customer focus, and address public policy responsiveness by complying with all legislative, regulatory, and environmental requirements. Below is a summary table showing how each of the Sustaining Capital programs align to the four key outcomes outlined in the OEB's Renewed Regulatory Framework for Electricity Distributors.

OEB Outcome	**Relevant References**	
Customer Focus	Section 3.3	Other Station Component Replacement Projects and Demand – Demand Work
	Section 4.1	Trouble Call and Storm Damage Response
	Section 4.2	Joint Use and Line Relocations
Operational Effectiveness	Section 3.1	Transformer Spares and Replacements
	Section 3.2	Mobile Unit Substations
	Section 3.3	Other Station Component Replacement Projects and Demand
	Section 3.4	Station Refurbishments
	Section 4.3	Asset Replacements
	Section 5.1	Customer Retail Meters
Public Policy Responsiveness	Section 3.2	Mobile Unit Substations
	Section 3.3	Other Station Component Replacement Projects – Spill Containment
	Section 4.1	Trouble Call and Storm Damage Response
	Section 4.2	Joint Use and Line Relocations
	Section 4.3	Asset Replacements - Lines PCB Equipment Replacements
	Section 5.1	Customer Retail Meters
	Section 5.2	Smart Meter Project
Financial Performance	Section 2.0	Sustaining Capital Summary

A summary of Hydro One Distribution's sustaining capital programs and proposed spending levels for the test years 2015 to 2019 are described herein.

2.0 SUSTAINING CAPITAL SUMMARY

The sustaining capital programs fund both planned work and unplanned demand work. The planned capital work involves the replacement, refurbishment or relocation of existing distribution system assets. Despite effective preventive maintenance programs, the condition of assets deteriorates over time. When assets become deteriorated, the cost to maintain the asset increases and there is a higher probability of failure that would negatively impact the safe and reliable operation of the system. Hydro One Distribution plans for the proactive replacement or refurbishment so as to reduce these cost and reliability impacts. However not all replacements are proactive, as severe storms or other adverse events can cause the sudden and catastrophic failure of assets requiring their immediate replacement to restore service. Furthermore, Hydro One Distribution has obligations to customers, joint use partners, regulatory agencies, or other third parties that would also require the removal or relocation of specific assets.

Demand capital work requires an immediate or timely response to customer, safety and system needs. This work includes responding to service interruptions, resolving public safety hazards, and replacing or repairing failed equipment. Due to the variable nature of demand work, Hydro One Distribution determines investment levels based on forecast volumes and costs using observed historical averages. Adjustments to this forecast are made based on the projected impact of any changes to the distribution system or to the planned investment programs.

The selection of planned sustaining capital investments is guided by the asset risk assessment process described in Exhibit A, Tab 17, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. An economic evaluation is also performed as part of the process. A summary of the asset risk assessment results is provided in Exhibit D1, Tab 2, Schedule 1.

Over the long term, an adequately maintained distribution system that performs to the level of its original design is in the best interest of Hydro One Distribution and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1 a significant portion of Hydro One's distribution system is at an age where factors such as degraded condition and demographic pressures are contributing to operational risks. These risks must be managed in a cost-effective manner for the benefit of customers. Capital expenditures proposed in this exhibit address the needs identified in the test years as a result of the aging asset base. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future, and the ability to complete the required work, both in capital replacements and corrective maintenance as well as impact reliability and potentially safety.

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 17, Schedules 1 to 5, respectively, has been completed for all planned and demand sustaining capital investments in the five test years to ensure that assets are managed prudently so as to meet customer, operational and regulatory requirements. The test year expenditures for Sustaining Capital along with the historical and bridge spending are provided in Table 1 below.

Table 1
Sustaining Capital
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Stations*	13.8	21.2	32.7	56.5	50.6	63.9	67.8	68.5	76.4	77.2
Lines*	170.0	181.2	183.2	234.4	203.9	227.6	246.8	267.4	282.7	295.8
Meters	130.1	71.8	45.9	32.3	31.9	16.6	20.6	23.8	21.3	10.5
Total	**314.0**	**274.2**	**261.8**	**323.2**	**286.4**	**308.2**	**335.2**	**359.7**	**380.4**	**383.5**

*Note: As stipulated in the Board's Renewed Regulatory Framework, no distinction has been made for smart grid investments, the deployment of these technologies will be implemented as part of the normal course of business as part of Stations and Lines capital replacements. An effort to provide some visibility to the smart grid costs were outlined in the Stakeholder Consultation Discussion presentation on December 2, 2013, please refer to Exhibit A, Tab 20, Schedule 1, Appendix E.

The increase in overall spending in the test years relative to historical expenditures is largely attributed to the following:

- An increase in stations capital expenditures to address the number of station transformers and other station components that are either approaching or beyond their expected service life; and
- An increase in lines capital expenditures to:
  - replace wood poles and line components that are either approaching or beyond expected service life;
  - replace a subset of wood poles that are showing signs of premature decay;
  - refurbish or replace submarine cables to mitigate reliability and safety risks; and
  - replace PCB oil-filled equipment to satisfy requirements set out by Environment Canada regulations.

The proposed expenditures in test years are felt to adequately maintain reliability to customers and manage the population of aging assets over this time period. Expenditures are focused on assets that are beyond their expected service life, have been identified as in degraded condition, are obsolete with no spare parts available, and/or require replacement in order to satisfy changes in the regulations that govern Hydro One Distribution's business.

While these Sustaining Capital expenditures will maintain reliability to customers they are not at a level which will lead to a reduction in Sustaining OM&A expenditures over the test years. As outlined in Exhibit D1, Tab 2, Schedule 1, asset demographics will continue to create a challenge in managing the distribution system. The effectiveness of Hydro One Distribution's maintenance programs have minimized the impact of aging assets on customers. However, equipment performance and condition trends reveal the necessity for continued investment to maintain the historic levels of risk.

One notable difference in the test year spending is the on-going focus on integrated projects in both the Stations and Lines asset categories. With many asset types beyond their expected service life and showing signs of the need for replacement, larger scale

Station or Line refurbishment projects are an effective option to deal with the specific assets and in many cases make modifications that would not otherwise be practical. This may include refurbishing a distribution station or rebuilding entire feeder sections to existing standards to eliminate safety risks. In the case where a distribution station has been completely rebuilt, the equipment reliability at that station will improve and there will be savings in maintenance costs where old and degraded equipment is replaced with new equipment.

Reduction in the Sustaining Capital funding would have impacts in a number of areas:

- A marked reduction in equipment and customer reliability at distribution stations as a result of increased transformer failures;
- Risk of non-compliance with Ministry of Environment regulations concerning lack of progress against PCB phase out plans mandated by Environment Canada;
- An increase in power outages to lines facilities due to failure of poles, insulators and other components that make up the lines system. These facilities are located in the public domain and as such need to be kept in a state of good repair to adequately manage public safety and to maintain customer and system reliability.

Additional details concerning these increases and a discussion of year over year variations in spending, where significant, are provided below.

3.0 STATIONS

Hydro One Distribution has 1,004 distribution and regulating station facilities province-wide. Distribution stations are used to lower voltages for more localized delivery of power while regulating stations are used to maintain voltages when feeders are long and customer density is low. Station facilities typically contain the following components: transformers, instrument devices, fuses, reclosers, disconnect switches, bus, insulators, support structures, power cables, cable terminators, surge arrestors, station service supplies, grounding systems, fences, and buildings. Hydro One Distribution also owns and maintains a fleet of 28 mobile unit substations that are used to provide emergency backup following a failure, and to facilitate planned maintenance and capital replacement activities at distribution and regulating stations to reduce power interruptions.

Stations Sustaining Capital funding covers capital investments required to replace or upgrade assets located within distribution and regulating stations, and on mobile unit substations. Hydro One Distribution manages its Stations Sustaining Capital program in four areas.

1. Transformer Spares and Replacements, which funds the capital investments to purchase spare transformers to support the in-service population of transformers, as well as the planned replacement of existing transformers within distribution stations;
2. Mobile Unit Substations, which funds the capital investments to refurbish and renew the fleet of mobile unit substations used to provide backup support in the event of failures and to allow continuity of service to customers as planned work is completed;
3. Other Station Component Replacements and Demand, which funds planned capital investments to refurbish or replace individual components within the station; as well as investments related to demand work to address component failures; and
4. Station Refurbishments, which funds the capital investments to integrate the replacement of several station assets that have reached expected service life and/or where the condition has degraded to a point that becomes a safety, environmental, or reliability risk.

Required funding for the test years 2015 to 2019, along with the spending levels for the bridge and historical years are provided in Table 2 for each of these areas.

Table 2
Stations Sustaining Capital
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Transformer Spares and Replacements	3.9	8.7	18.1	18.4	14.6	18.0	18.4	17.9	21.2	21.6
Mobile Unit Substations	1.0	3.4	1.7	1.8	3.7	4.6	3.6	3.7	3.6	3.7
Other Station Component Replacements & Demand	6.1	6.7	6.9	9.9	6.2	6.7	6.8	6.9	7.1	6.6
Station Refurbishments	2.7	2.3	6.0	26.3	26.1	34.6	39.0	40.0	44.5	45.2
Total	**13.8**	**21.2**	**32.7**	**56.5**	**50.6**	**63.9**	**67.8**	**68.5**	**76.4**	**77.2**

The overall Stations Capital investment for the test year 2015 is approximately 25% greater than the 2014 bridge year. The Stations Capital investment continues to grow on average 5% annually over the five year period. These expenditures reflect the increased asset replacement rates required to maintain reliability and risks levels on an on-going basis. The primary drivers for the escalation in the Stations Capital investment include:

- The increase in the number of transformers required to address the ageing demographics and associated degradation of the asset condition; and
- The increase in the number of station refurbishments to improve the existing risk profile of the station assets in order to sustain the safe and reliable operation of the distribution system.

3.1 Transformer Spares and Replacements

3.1.1 Introduction

Transformers are the major and most expensive asset at the distribution stations. Transformers are used to step down voltage levels for local power delivery and to provide voltage control. Hydro One Distribution has 1,214 station transformers in service and also maintains an inventory of strategic spare transformers.

Hydro One Distribution's system is largely radial meaning there is limited or no load transfer capability. By design, the majority of distribution stations are equipped with only one transformer. While this is a cost effective system design, unfortunately a transformer failure at a distribution station results in a service interruption to all customers supplied from that station.

3.1.2 Investment Plan

The management of transformer assets is a key component of the Stations Capital Sustaining program. To maximize supply reliability, transformers are managed through a proactive replacement program and coordinated use of strategic spare transformers.

Transformer Replacements

The transformer replacement program is in place to replace existing distribution transformers that have reached or exceeded their expected service life. Presently, 19% of the transformer population is beyond expected service life, as outlined in Exhibit D1, Tab 2, Schedule 1. This percentage will continue to increase if Hydro One Distribution carries on with its historical planned replacement rate which addresses less than 1% of the transformer fleet annually.

An ageing asset base also increases the likelihood of failure, as the condition of the transformer internal components degrade as a function of time. Distribution transformer failures are highly impactive as the interruption affects all customers supplied from the station. The duration of restoration can also be significant; as a failed transformer typically requires removal from site and replacement with a transformer from the strategic spare transformer inventory. Hydro One Distribution mitigates this risk by utilizing diagnostic and oil testing to identify and proactively remove transformers that are at a high risk of failure. However, it is not possible to eliminate all risk of major failures. There continues to be an increasing trend in transformer failures and transformers at high risk of failure at distribution stations. The replacement of end of life transformers are required to mitigate impacts to system reliability, environment, customer interruptions, and safety.

In order to manage the transformer population an asset risk assessment is undertaken. The level of replacements and priority of replacements are based on the results of this assessment.

Strategic Spare Purchases

The strategic spare purchases program is in place to maintain an inventory of transformers for use when failures or emergency demand work must be undertaken to maintain service to customers. A strategic inventory of spare transformers is critical to ensuring service restoration is completed in a timely manner following a failure. The number of spare transformers to support each type of transformer is based on the in-service transformer population volume, condition and reliability combined with failure history, obsolescence, and the availability of mobile unit substations. In order to maintain an effective inventory of spare transformers, inventory levels must be maintained through replenishment after units are taken out to replace failed units on the system.

The inventory is replenished by purchasing new transformers or by refurbishing existing units. The cost to refurbish a transformer can vary significantly depending on the condition of the unit. Hydro One Distribution assesses the type of transformer and its value in the strategic spare inventory, and if warranted, estimates the cost to refurbish. If refurbishment is technically acceptable and economically viable based on the age and condition of the transformer, the existing transformer is refurbished and added to the inventory of strategic spare transformers. Technical and economic assessments increasingly support the purchase of new units versus refurbishing transformers that have already experienced many years of service.

By maintaining an adequate inventory of spare transformers, Hydro One Distribution can ensure operational effectiveness by reducing the duration of power interruptions to customers and improving the reliability of the distribution system.

For additional details on the Transformer Spares and Replacements program refer to the Investment Summary Document S1 in Exhibit D2, Tab 2, Schedule 3.

3.1.3 Summary of Expenditures

The planned expenditure for 2015 is $18.0 million with proposed spending increasing over the five year period on average by 5% annually. This represents an average increase of 50% over the average historical spending. This increase is required due to the degrading condition of the existing transformer fleet; and the increasing trend of major transformer failures and transformers at high risk of failure on the distribution system.

3.2 Mobile Unit Substations

3.2.1 Introduction

A mobile unit substation is essentially a distribution station mounted on a trailer suitable for traveling on public roads. These mobile unit substations consist of a transformer, high voltage and low voltage switches, high voltage and low voltage fuses, and connecting bus. Currently, Hydro One Distribution owns 28 of these mobile unit substations strategically located across the province. The primary purpose of a mobile unit substation is to provide emergency backup to distribution stations and restore service to customers following the failure of a station. They also facilitate planned capital and maintenance programs for distribution station assets by carrying the station load while the station is isolated to perform work thereby mitigating power disruption to customers. Given Hydro One Distribution's largely radial distribution system with single transformer distribution stations, the utilization of mobile unit substations provides a cost effective alternative to constructing redundant transformation at stations across the province.

3.2.2 Investment Plan

In order to manage the fleet of mobile unit substations an asset risk assessment is undertaken as outlined in Exhibit A, Tab 17, Schedule 7. Presently, 61% of the mobile unit substation transformers and 39% of the mobile unit substation trailers are beyond their expected service life, as outlined in Exhibit D1, Tab 2, Schedule 1. As mobile unit substations are utilized and age, the condition of their various components deteriorates. Monthly and yearly condition assessments are required to ensure the mobile unit substations are roadworthy, electrically functional, and comply with Ministry of Transportation licensing requirements. In order to maintain the condition of these units, refurbishment or replacement is required to critical electrical (e.g. transformers, reclosers, switches) and mechanical (e.g. trailer running gear, wheels, axles, suspension) components when routine maintenance cannot restore their integrity.

The programs used to strategically manage the fleet are provided below.

Mobile Unit Substation Refurbishments

The mobile unit substation refurbishment program is in place to refurbish and replace components of the mobile unit substations. This program targets the refurbishment of the trailers and replacement of transformers that have reached their expected service life or have shown signs of deterioration. The level of replacements and priority of replacement are based on the asset risk assessment results outlined in Exhibit D1, Tab 2, Schedule 1.

Mobile Unit Substation Purchases

The mobile unit substation purchases program is in place to purchase new mobile unit substations. Capital projects, failures and planned maintenance activities all require the installation of a mobile unit substation to supply the load to minimize outage impact to customers. The addition of units to the fleet is based on ensuring there is an adequate number and type of mobile unit substations available to support the initiatives required to maintain and upgrade the distribution system.

By maintaining an adequate inventory of mobile unit stations through refurbishment and procurement, Hydro One Distribution can ensure sufficient mobile unit substation coverage to address power restoration as well as provide for operational effectiveness while executing planned capital and maintenance program by reducing the duration of power interruptions to customers and improving the reliability of the distribution system.

For additional details on the Mobile Unit Substations program refer to the Investment Summary Document S2 in Exhibit D2, Tab 2, Schedule 3.

3.2.3 Summary of Expenditures

The planned expenditure for 2015 is $4.6 million with proposed spending over the five year period averaging $3.6 million annually. This represents an increase over the historical spending. This increase is required to ensure the existing fleet remains in good working condition and is readily deployable; as well as to maintain an adequate mobile unit substation inventory to support the required increase in work programs to sustain a reliable distribution system.

3.3 Other Station Component Replacement Projects & Demand

3.3.1 Introduction

In addition to distribution station transformers and mobile unit substations there are other components and system elements that are an integral part to the operation of a distribution station. These include instrument devices, reclosers, fuses, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station services, grounding systems, fences, and buildings. These assets require replacement or refurbishment to allow the distribution stations to operate properly.

3.3.2 Investment Plan

In order to better manage station component replacement projects, four programs of work are defined. Required funding for the test years 2015 to 2019, along with spending levels for the bridge and historical years are provided in Table 3 for each of these programs.

Table 3
Other Station Component Replacements & Demand
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Spill Containment	0.3	0.6	1.3	1.9	1.1	1.1	1.1	1.2	1.2	0.6
Station Component Replacements	2.7	4.6	2.4	3.8	2.1	2.1	2.2	2.2	2.2	2.3
Recloser Upgrades	0.5	0.3	0.5	1.3	1.0	1.4	1.4	1.4	1.5	1.5
Demand Work	2.6	1.2	2.7	2.9	2.0	2.1	2.1	2.1	2.2	2.2
Total	**6.1**	**6.7**	**6.9**	**9.9**	**6.2**	**6.7**	**6.8**	**6.9**	**7.1**	**6.6**

Spill Containment

The spill containment program involves the installation of spill containment systems at distribution stations. Spill containment systems are utilized to capture and control transformer oil spills and leaks. For distribution stations, these systems were not generally installed at the time of construction since environmental regulations did not require them at that time. As a result, a relatively small portion of the distribution stations have spill containment systems.

Hydro One Distribution has identified high risk station sites that currently do not have spill containment systems and that would benefit from their installation. These high risk sites are typically in proximity to waterways and pose environmental risks should transformer insulating oil be released off of the distribution station site.

Hydro One Distribution demonstrates effective public policy responsiveness and corporate risk mitigation by proactively managing its transformer spill containment system infrastructure adhering to the Ministry of Environment's *Environmental Protection Act*.

For additional details on Spill Containment refer to the Investment Summary Document S3 in Exhibit D2, Tab 2, Schedule 3.

Station Component Replacements

The station component replacement program involves replacing defective equipment such as switches, fuses, fences and structures that are at end of their service life. Replacements are based on the condition of the station components assessed during routine inspections and planned maintenance activities. Replacement decisions may also be made based on identified safety risks or technology obsolescence. The replacement of these station components ensures the continued operation of the distribution system which plays an important role in maintaining the level of reliability to customers. For additional details on the Station Component Replacements program refer to the Investment Summary Document S4 in Exhibit D2, Tab 2, Schedule 3.

Recloser Upgrades

The recloser upgrade program involves replacing reclosers that have reached the end of their expected service life, are obsolete, or defective. The program will also address feeders that currently only use fuses for protection; as well as reclosers that have insufficient short circuit rating. The reclosers will be replaced with new units that utilize vacuum technology. The technology of the older reclosers is becoming obsolete and no longer supported by the manufacturer, as manufacturers shift into producing a new generation of reclosers with remote control and monitoring features consistent with smart grid requirements. The level of replacements and priority of replacement are based on the asset risk assessment results outlined in Exhibit D1, Tab 2, Schedule 1. The new reclosers once installed will provide operational effectiveness through cost savings due to reduced maintenance cycles, and improve reliability due to more flexibility and accuracy with settings. For additional details on the Recloser Upgrades program refer to the Investment Summary Document S5 in Exhibit D2, Tab 2, Schedule 3.

Demand Work

The demand work program covers the capital component of work required to address component failures and emergency replacement work at distribution and regulating stations. These are situations where there is a likelihood of failure that could cause a power interruption or that presents a safety hazard to the public as well as Hydro One Distribution personnel. Hydro One Distribution must address these station interruptions to maintain reliable service in accordance with good utility practice in order to comply with legal and regulatory requirements. Hydro One Distribution's performance in responding to interruptions is reflected by service quality indicators specified in the OEB's Distribution System Code, Section 7, and in the Electricity Distribution Rate Handbook, Sections 15.2.1 and 15.2.3.

In most cases, smaller components such as insulators, connectors, switches, etc. will be repaired, temporarily bypassed, or replaced on site. The failure of a large component, such as a transformer, may require moving the equipment from site and repairing it at a central location or replacing it.

Demand work must be carried out in a timely manner in order to minimize the risks to customer reliability, and public and employee safety. Demand work that does not involve capital components or plant retirements is covered under the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2. For additional details on the Demand Work program refer to the Investment Summary Document S6 in Exhibit D2, Tab 2, Schedule 3.

3.3.3 Summary of Expenditures

The planned expenditure for these component and demand work programs in 2015 is $6.7 million with proposed spending over the five year period remaining on average at $6.8 million annually. There is some year over year variation due to the nature of demand work, but the overall planned expenditures are in line with the average historical spending.

3.4 Station Refurbishments

3.4.1 Introduction

Older stations typically contain a number of components that reach their expected service life and exhibit degrading conditions or design deficiencies that result in safety and customer supply reliability risks at about the same time. As such, Hydro One Distribution is able to achieve operational effectiveness through efficiency gains achieved by replacing all such components within the station as part of the same project. The result is a station that functions as originally designed and ensures the assets are brought to current safety and equipment standards and are compatible with future modernization of the distribution system. This integrated approach to station refurbishment contributes to greater customer satisfaction by reducing the number of planned outages at the station, and reducing the risk of unplanned outages that can occur when one or more system elements fail.

Hydro One Distribution has also developed a new prefabricated integrated modular distribution station containing a transformer and switchgear mounted on a platform which forms a complete station. The introduction of the integrated Modular Distribution Station (iMDS) will provide a more cost effective solution to station refurbishments where space is limited especially in urban areas. The modular design is also more aesthetically pleasing compared to existing designs.

3.4.2 Investment Plan

The integrated station refurbishments will allow for the complete rebuild or replacement of part of a station to address stations with multiple assets in degraded condition in the most effective manner.

The level of investment required to refurbish a station will vary as a function of the condition and voltage of the station. A typical station refurbishment would include the replacement of several station components such as: the transformer, station fence and ground grid, low and high voltage structure, reclosers, metalclad breakers, associated ancillary equipment, concrete structures or provision for load transfer and back-up capability. In other cases, the work required may be more significant and require a complete rebuild of a station on an existing or a new site.

The strategy is to address stations that are at a high risk of failure as determined by the asset risk assessment and prioritized based on the impact of failure of key factors including customer, safety and environmental risks. For additional details on Station Refurbishments refer to the Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

3.4.3 Summary of Expenditures

The planned expenditure for 2015 is $34.6 million with proposed spending increasing over the five year period on average by 7% annually. This represents a significant increase over historical spending levels. Hydro One Distribution has currently been refurbishing less than 1% of its distribution stations annually. In order to manage the risk of failure associated with the condition of this aged station infrastructure, an increase in station refurbishments is required. This increase in station refurbishments will improve customer service reliability, safety and maintainability, as well as reduce maintenance costs.

4.0 LINES

Distribution lines total approximately 120,000 circuit kilometres province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way that Hydro One Distribution can legally access and occupy. Line components include poles, conductor, insulators, transformers, switches, fuses, surge arresters, voltage regulators, reclosers, capacitors, and grounding devices. A small proportion of the distribution line inventory consists of underground cables which are located mainly in more urban areas or submarine cables which traverse water when overhead crossings are technically or economically unfeasible.

Lines Sustaining Capital investments are required to maintain the integrity of the distribution lines system. Hydro One Distribution manages its Lines Sustaining Capital program by dividing it into three categories.

1. Trouble Call & Storm Damage Response, which are demand driven capital investments to respond to interruptions in service, deficiencies requiring immediate attention, and storm damage restoration.
2. Joint Use & Line Relocations, which are capital investments to modify existing Hydro One Distribution line assets to accommodate joint use partners and Provincial and Municipal road authorities.
3. Asset Replacements, which are the capital investments to replace distribution lines and line components, including but not limited to wood poles, submarine cables, and reclosers.

Required investment levels for the test years 2015 to 2019, along with investment levels for the bridge and historical years are provided in Table 4 for each of these categories.

Table 4
Lines Sustaining Capital
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Trouble Call and Storm Damage Response	53.4	78.7	66.3	102.8	58.3	58.2	60.8	61.6	62.0	62.5
Joint Use and Line Relocations	36.3	20.1	23.2	26.2	26.2	26.7	27.3	27.8	28.4	28.9
Asset Replacements	80.3	82.4	93.7	105.4	119.3	142.7	158.7	178.0	192.3	204.4
Total	**170.0**	**181.2**	**183.2**	**234.4**	**203.9**	**227.6**	**246.8**	**267.4**	**282.7**	**295.8**

The Lines Sustaining Capital expenditures in 2013 are higher than initially forecasted, largely due to unusually intense storms during the months of November and December.

The overall Lines Capital investment for the test year 2015 is approximately 12% greater than the 2014 bridge year. The Lines Capital investment continues to grow on average 7% annually over the five year period. The primary driver for this increase is the need to increase the number of asset replacements to address ageing demographics and the associated degradation of asset condition.

4.1 Trouble Call and Storm Damage Response

4.1.1 Introduction

This demand work program provides capital investment for responding to customer service interruptions, severe deficiencies requiring immediate attention, and storm damage restoration.

4.1.2 Investment Plan

The externally driven nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect anticipated changes in expenditure patterns or work requirements. The details of the demand work program are provided below.

Trouble Calls

Trouble Calls typically involve the restoration of service to customers impacted by an unplanned power interruption. Unplanned power interruptions on the distribution system are largely due to line component failures or contact with right-of-way vegetation caused by severe weather conditions. Depending on the specific circumstances, these interruptions can vary in size, from impacting single customers for brief periods of time to impacting thousands of customers for several hours. Trouble calls may also be used to respond to customer complaints related to power quality or to correct defects on the distribution system that present a safety concern or could result in an imminent service interruption.

The majority of costs associated with trouble calls are incurred in the Sustaining OM&A program described in Exhibit C1, Tab 2, Schedule 2. In cases where capital plant is replaced as part of a trouble call, all labour and material costs are capitalized under this program. Where a trouble call is as a result of damage to the distribution system caused by a third party, Hydro One Distribution endeavours to recover the cost of making the repairs. Any costs recovered are credited to this program. Historically, damage by third parties has totaled approximately $4 to $5 million per year with recovery of approximately $2 to $3 million annually.

Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements, to correct known hazards and to maintain reliable service in accordance with good utility practice. Hydro One Distribution's performance in responding to trouble calls is reflected by service quality indicators specified in the OEB's Distribution System Code, Section 7, and in the Electricity Distribution Rate Handbook, Sections 15.2.1 and 15.2.3. The Distribution System Code states that *"emergency calls must be responded to within 120 minutes in rural areas…and must be met at least 80% of the time on a yearly basis"*. Hydro One Distribution's targets for emergency response are discussed in Exhibit A, Tab 18, Schedule 1.

<u>Storm Damage Response</u>

Storm damage can interrupt the supply of power to many thousands of customers simultaneously. The impact storms have on Hydro One Distribution's system during any given year varies widely, and depends on the number, type, and intensity of storms during that year. When a severe storm results in an interruption to over 10% of Hydro

One customers, it is classified as a "force majeure" storm. Over the past decade, the number of force majeure storms has varied widely. Given the highly variable nature of weather and intensity of storms, expenses related to storm damage can change significantly from one year to the next.

The extent of storm damage can be mitigated by Hydro One Distribution's sustainment programs. For example, increasing the amount of vegetation management performed will decrease the likelihood of trees and branches contacting a line under storm conditions. As a second example, increasing the number of end-of-life poles replaced can decrease the number of such poles that fail under storm conditions.

Hydro One Distribution capitalizes the repair of storm damage when such repair involves the replacement of capital equipment. The full costs of these repairs are capitalized, with the exception of any overtime or vegetation management costs.

For additional details on the Trouble Calls and Storm Damage Response program refer to the Investment Summary Document S8 in Exhibit D2, Tab 2, Schedule 3.

4.1.3 Summary of Expenditures

The planned expenditure for 2015 is $58.2 million with the proposed spending increasing over the five year test period on average by 2% annually. The proposed spending in the test years is based on a five year average of historical spending with adjustments made to incorporate recent trending in volumes and cost.

4.2 Joint Use and Line Relocations

4.2.1 Introduction

The Joint Use and Line Relocations program is a customer focused program that addresses externally driven customer requirements which Hydro One Distribution is obligated to undertake in accordance with reciprocal agreements with joint use partners.

4.2.2 Investment Plan

The externally driven nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect anticipated changes in expenditure patterns or work requirements. The details of this program are provided below.

Joint Use

The joint use component of this program covers the work required to modify existing Hydro One Distribution assets to accommodate telecommunication or cable television lines, street lighting owned by municipalities, or power circuits for various Local Distribution Companies (LDCs) or generators.

The joint use program is driven by external demand for work which Hydro One Distribution provides in accordance with joint use agreements. The number and size of joint use projects in any given year can vary widely. A typical year can involve between one and two hundred projects usually costing less than $50,000 each. Depending on project details, however, the cost may be significantly higher.

Hydro One Distribution carries out these joint use projects in accordance with agreements between Hydro One Distribution and joint use partners. The cost sharing provisions in these agreements allow Hydro One Distribution to recover some of its costs. Historically, 25% to 35% of a joint use project costs are recoverable. The recoverable portion represents the residual value of the line assets at the time the joint use project is initiated plus the incremental cost of any modifications required for the new joint use facilities. The unrecoverable portion of the costs recognizes that these projects generally result in increased life of the facilities that benefit Hydro One Distribution customers, due to a reduction of future investment needs.

All recoverable joint use costs are paid by joint use partners at the time of the attachment. In addition, annual fees are levied per attachment to compensate for ongoing incremental maintenance costs due to the presence of these attachments on the pole. Revenues associated with these annual fees are discussed in Exhibit E1, Tab 1, Schedule 2.

Line Relocations

The line relocation component of this program primarily covers the work required to relocate assets in response to road modifications. Hydro One Distribution is required to make these relocations by the *Public Service Works on Highways Act* (R.S.O. 1990), and associated Ministry of Transportation guidelines. Asset relocations may also be initiated by customer request, as specified in the Hydro One Conditions of Service. Asset relocation may involve the installation of new assets and removal of existing assets.

The cost of a relocation project is either fully or partially recoverable. In the case of a project associated with road modifications, applicable statutes provide guidance for cost allocations. Hydro One Distribution has typically recovered 20% to 35% of the total cost of these relocations. In the case of a project associated with a customer request, Hydro One Distribution recovers all associated costs from the customer.

The number of relocation projects can vary significantly from year to year depending on the number of government infrastructure improvement projects and economic conditions influencing individual third party development projects.

For additional details on the Joint Use and Line Relocations program refer to the Investment Summary Document S9 in Exhibit D2, Tab 2, Schedule 3.

4.2.3 Summary of Expenditure

The planned expenditure for 2015 is $26.7 million, increasing over the five year period on average by 2% annually. Since the number of individual joint use and line relocation projects varies from year to year, the planned expenditures are based on historic costs, taking into account any observed trending and any specifically identified joint use or relocation work.

4.3 Asset Replacement

4.3.1 Introduction

The asset replacement program replaces line components and line sections that have reached the end of their life or require modifications to address safety and reliability issues. Where appropriate, these activities are coordinated and integrated with System Capability Reinforcement plans (Exhibit D1, Tab 3, Schedule 3) to maximize the benefits of these investments and ensure operational effectiveness.

4.3.2 Investment Plan

In order to better manage asset replacement activities, three programs of work are defined. Required funding for the test years 2015 to 2019, along with spending levels for the bridge and historical years are provided in Table 5 for each of these programs.

Table 5
Asset Replacement
($ Million)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Pole Replacements	53.6	54.7	55.5	73.9	82.5	88.7	95.1	105.0	115.2	125.8
Lines PCB Equipment Replacements	1.7	0.8	1.0	1.1	0.0	1.9	5.0	10.6	10.8	11.1
Line Projects	25.0	26.9	37.2	30.3	36.8	52.1	58.6	62.4	66.3	67.5
Total	**80.3**	**82.4**	**93.7**	**105.4**	**119.3**	**142.7**	**158.7**	**178.0**	**192.3**	**204.4**

Pole Replacements

The pole replacement program involves replacing poles that are at their end of life. In order to manage this population, an asset risk assessment is undertaken as outlined in Exhibit A, Tab 17, Schedule 7. Presently, approximately 11% of the pole population exceeds its expected service life, as documented in Exhibit D1, Tab 2, Schedule 1. Hydro One Distribution has been mitigating the risk of failure by selectively targeting replacement of end of life poles. Over the next several years, an increasing number of poles are expected to reach the end of their service life. A corresponding increase in the pole replacement rate is required to prevent the pole population from reaching an unmanageable state. An ageing pole population increases the likelihood of failures on the distribution system, as the structural integrity of a distribution line is largely dependent on its pole supports.

In addition to concerns with demographics, Hydro One Distribution continues to address a subset of red pine poles that are demonstrating premature deterioration. The deteriorating condition of these poles places upward pressure on the numbers of poles on the distribution system requiring replacement.

Due to the large number of poles in the system, the pole population must be managed proactively through planned replacements. If the population is allowed to deteriorate until there is a significant impact on safety and reliability, available resources will not be sufficient to manage the large number of replacements that will be rapidly required. Furthermore, the replacement of poles on a reactive (or "emergency") basis results in increased labour costs, longer outage durations, and increased safety risks. A proactive approach to pole replacement allows for increased bundling of work and improved efficiencies. It is also a good utility practice that will mitigate the related risks associated to the future safety, reliability, and manageability of the distribution system. For additional details on the Pole Replacements program refer to the Investment Summary Document S10 in Exhibit D2, Tab 2, Schedule 3. Hydro One Distribution's targets for these replacements are discussed in Exhibit A, Tab 4, Schedule 4.

Lines PCB Equipment Replacements

The lines PCB equipment replacement program involves replacing oil filled lines equipment that have PCB contamination levels in excessive of regulatory limits. Hydro One Distribution inspects and tests equipment for PCB contamination in compliance with Environment Canada legislation. This testing program is described in Exhibit C1, Tab 2, Schedule 2. Hydro One Distribution initially focused on the inspection and testing of pad-mounted transformers; as such the replacement program from 2009 to 2013 addressed the replacement of pad mounted equipment. Beginning in 2014, pole mounted lines equipment will be inspected and tested. Hence the replacement program in 2015 and going forward will focus on the replacement of pole mounted equipment. These replacements ensure that Hydro One Distribution operates in an environmentally responsible manner that minimizes the risk to human health and the environment and remains in compliance with applicable regulations. For additional details on the Lines PCB Equipment Replacements program refer to the Investment Summary Document S11 in Exhibit D2, Tab 2, Schedule 3. Hydro One Distribution's targets for these replacements are discussed in Exhibit A, Tab 4, Schedule 4.

Line Projects

These investments address a wide variety of issues on the distribution system. They can vary in size and scope from system wide sustainment projects to individual component replacements, depending on the nature of the required work. A decision as to the most appropriate course of action is made in each case taking into account the overall asset risk assessments as well as current and future load requirements.

Lines large sustainment initiative projects involve the refurbishment or replacement of entire feeders or feeder sections. By replacing sections with high projected maintenance costs or with a high number of components reaching their end of life, a large number of assets are replaced in a cost effective manner achieving operational effectiveness. These projects often involve the relocation of assets to more accessible locations or upgrading assets with new distribution automation technology, improving future reliability and productivity. They also address local reliability and power quality issues that do not have a system-wide impact. This integrated approach to line refurbishment or replacement contributes to greater customer satisfaction by reducing the number of planned outages on the circuit, and reducing the risk of unplanned outages that can occur when one or more system elements fail. In order to further maximize the benefit of these projects, they are integrated with any applicable System Capability Reinforcement plans (Exhibit

D1, Tab 3, Schedule 3). For additional details on Large Sustainment Initiatives refer to the Investment Summary Document S12 in Exhibit D2, Tab 2, Schedule 3.

Component replacement programs address individual assets that cannot be efficiently bundled into large sustainment initiative projects. These programs target the replacement of deficient overhead line components including switches, regulators, reclosers, transformers and crossarms; as well as the replacement of deteriorated submarine cables. As these assets are replaced, Hydro One Distribution will look for opportunities to improve reliability through distribution modernization and installation of assets capable of remote monitoring and control. Distribution line components are primarily identified as requiring replacement by the patrol program described in Exhibit C1, Tab 2, Schedule 2. For additional details on Line Component Replacements and Submarine Cable Replacements programs refer to the Investment Summary Documents S13 and S14 respectively in Exhibit D2, Tab 2, Schedule 3.

4.3.3 Summary of Expenditures

The planned expenditure for all line projects in 2015 is $142.7 million with proposed spending increasing over the five year period on average by 10% annually. This represents a significant increase over the historical spending. The increase in funding is required to address:

- the demographics of the pole population;
- the regulatory requirements for PCB oil-filled equipment; and
- the ageing plant and deteriorating conditions of other line equipment that poses unacceptable safety and reliability risks.

5.0 METERS

Hydro One Distribution currently owns and maintains revenue meters of two main types: Retail Revenue Meters and Wholesale Revenue Meters. The retail revenue meters are used to measure energy consumption for retail customers. Whereas the wholesale revenue meters are used to settle the purchase of energy where the point of supply is directly connected to the IESO-controlled grid.

Metering Sustaining Capital funding covers capital investments required to address retail revenue meter upgrades and conversions. No funding is required for wholesale revenue meters as all upgrades to the meters Hydro One Distribution is accountable for has been completed. There may be a need to undertake some 'customer driven' wholesale revenue meter upgrades; however the costs associated with these upgrades will be fully recovered from the customer and as such are not reflected in the plan.

Funding for the meters program from 2015 to 2019, as well as spending in the bridge and historic years, are provided in Table 6 below.

Table 6
Metering Capital
($Million)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customer Retail Meters	1.7	3.1	7.3	11.2	13.1	14.6	20.6	23.8	21.3	10.5
Smart Meter Project*	128.4	68.7	38.6	21.1	18.8	2.0	0.0	0.0	0.0	0.0
Total	**130.1**	**71.8**	**45.9**	**32.3**	**31.9**	**16.6**	**20.6**	**23.8**	**21.3**	**10.5**

**The Smart Meter Project costs have been tracked in a deferral account as approved in proceeding EB-2009-0096, the planned disposition of this account is outlined in Exhibit F1, Tab 1, Schedule 3.*

5.1 Customer Retail Meters

5.1.1 Introduction

Hydro One Distribution owns and operates approximately 1.2 million customer retail meters. There are three types of retail revenue meters utilized on the Hydro One distribution system based on average monthly energy demand. The types include:

- smart meters measuring energy consumption for residential and other customers whose average monthly demand is 50 kW or less under the Time of Use ("TOU") pricing scheme,
- electronic demand meters for smaller business customers with an average monthly electricity demand of greater than 50 kW, and
- interval meters for existing business customers whose demand exceeds 1,000 kW, recently connected customers whose demand exceeds 200 kW and customers below the threshold who have requested interval meters.

Retail revenue meters are required to be operated, maintained and verified in accordance with requirements of the *Electricity and Gas Inspection Act* administered by Measurement Canada.

5.1.2 Investment Plan

The customer retail meter program is divided into two categories: meter upgrades, and the sustainment of the retail meter inventory.

Table 7
Customer Retail Meters Capital
($Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Meter Upgrades	1.0	2.4	6.0	8.3	8.6	10.0	15.8	18.8	16.1	5.0
Meter Inventory Sustainment	0.7	0.7	1.3	2.9	4.5	4.6	4.8	5.0	5.2	5.5
Total	**1.7**	**3.1**	**7.3**	**11.2**	**13.1**	**14.6**	**20.6**	**23.8**	**21.3**	**10.5**

Meter Upgrades

The meter upgrade program addresses the replacement of meters and network components. Hydro One Distribution replaces meters due to a variety of drivers. One driver is related to the Distribution System Code, which requires an existing customer's demand meter to be upgraded to interval meter when the average annual monthly peak demand is equal to or greater than 1,000 kW. A second driver is the need to upgrade and standardize meters at acquired LDCs to enhance maintenance and meter reading system efficiency. Other drivers include the obsolescence of the metering telecommunications equipment; the need to install demand meters, and the modification of wholesale meters used by customers that did not decide to register with the IESO to participate in the wholesale market but instead chose to become retail customers of Hydro One Distribution. For additional details on Meter Upgrades refer to the Investment Summary Document S15 in Exhibit D2, Tab 2, Schedule 3.

Meter Inventory Sustainment

The meter inventory sustainment program maintains an inventory of retail revenue meters and network components. The inventory is required to efficiently and in a timely manner, replace in-service meters and network components that fail, get damaged, become obsolete, are retired due to reaching end of expected service life, or that cannot be returned to service through the re-verification program. By maintaining an adequate inventory of meters, Hydro One Distribution can ensure operational effectiveness by maintaining the level of reliability to customers and ensuring collection of energy consumption data required to focus on customer billing. For additional details on the Meter Inventory Sustainment refer to the Investment Summary Document S16 in Exhibit D2, Tab 2, Schedule 3.

5.1.3 Summary of Expenditures

The planned expenditure for the overall customer retail meter programs in 2015 is $14.6 million with proposed spending varying from a peak of $23.8 million in 2017 to a low of $10.5 million in 2019. However, the overall trend has been increasing since 2011 as the Smart Meter project began transitioning to sustainment mode.

The proposed spending for meter upgrades increases on average by 20% until 2018 primarily as a result of required telecommunication upgrades that will be completed by 2018, then the program resumes to historical spending levels. The proposed spending for the sustainment of the meter inventory is also increasing on average by 5% annually over the five year period to address a higher anticipated rate of failure for meters.

5.2 Smart Meter Project

The Government of Ontario with the enactment of the Energy Conservation Leadership Act defined its Smart Meter Initiative; prescribing the technical and functional requirements of the smart meter solutions and set the path for mass deployment of the meters across Ontario.

In line with the legislative and regulatory requirements, Hydro One Distribution has implemented its smart metering project, including smart meter deployment, communication network development, and updating the customer information systems and associated processes to enable it to support Time of Use and Regulated Price Plan implementation.

Hydro One Distribution has been tracking the costs of its smart metering project in a deferral account, as approved in proceeding EB-2009-0096 for the 2010/2011 Distribution Rates. These costs have been provided in Table 6 for continuity; however please refer to Exhibit F1, Tab 1, Schedule 3, Attachment 1, for the details and justification of these costs.

DEVELOPMENT CAPITAL

1.0 INTRODUCTION

Development capital represents investments required to connect new load and generation customers, and to enhance existing, or construct new, distribution facilities. These investments ensure the system's capability to provide a secure and reliable supply of electricity in response to new large load customer connections, cumulative system-wide load growth and system demands associated with new generators. Growth is predicted through the combined use of load-forecast models, historical growth patterns, and specific load measurements taken at times of heavy loading during the year. The table below provides a summary of how each of the program areas aligns to the four key outcomes in the OEB's Renewed Regulatory Framework for Electricity Distributors.

OEB Outcome	**Relevant References**	
Customer Focus	Section 3.1	New Connections, Service Upgrades and Metering
	Section 3.3	Generation Connections
Operational Effectiveness	Section 3.2	System Capability Reinforcement
Public Policy Responsiveness	Section 3.1	New Connections, Service Upgrades and Metering
	Section 3.2	System Capability Reinforcement
	Section 3.3	Generation Connections
Financial Performance	Section 3.2	System Capability Reinforcement

Adressing Line Losses on the Distribution System

Hydro One was asked at the Technical Conferences in this proceeding about its efforts to address line losses on the distribution system. Within the System Capability Reinforcement Program, reductions in overall line losses experienced by customers are considered when developing these investments, including:

- **Upgrading the conductor size:** upgrading the conductor size reduces the overall line resistance. For example for a 3-phase line carrying 150A of load per phase, upgrading the conductor from #2 ACSR to 3/0 ACSR reduces line losses by 35 kW per km
- **Voltage conversion:** increasing the voltage levels decreases the amount of current flowing through the conductor and thereby decreases line losses. For example, converting 150A at 8.32 kV to 27.6kV can result in line loss savings of 20 kW per km with 3/0 ACSR
- **New Feeder Load Relief:** installing a new feeder to offload a heavily loaded feeder again reduces the overall current passing through the conductors. For example, splitting 400A from one feeder into two can result in a line loss saving of 25 kW per km with 556kcmil AL conductor
- **Station Decommissioning:** by eliminating a distribution station through voltage conversion, additional loss savings are found by removing the station transformer. For example if a transformer’s losses are 1% and it was loaded to 3MW, its decommissioning would result in 30kW of loss savings
- **Converting line sections from single-phase to three-phase:** by providing additional phasing, less current passes through individual conductors, which then reduces line losses. For example, if a 150A single-phase section is divided equally into three-phases with 50A per phase on 3/0 ACSR conductor, a loss saving of 5kW per km is achieved
- **Power Factor Correction:** by installing capacitor banks to improve the power factor, line loss savings are also seen. For example, 2kW per km can be saved by

adding a capacitor bank that improves the power factor from 0.9 to 1.0 on a 100A loaded section with 3/0 ACSR conductor.

Although line losses are not the principle driver behind these investments, they are considered when comparing potential solutions such that multiple benefits are seen from the investment.

2.0 DEVELOPMENT CAPITAL SUMMARY

Development capital programs fund both planned work and demand work that results from customer connection requests and other factors that must be responded to on demand.

2.1 Demand Work

Demand work represents the largest component of the program and involves work required to connect new load or generator customers or to modify an existing customers' service. In accordance with our Distribution License, Hydro One is required to make an offer to connect new distribution customers on a non-discriminatory basis when requested by customers. Connections and Upgrades are considered demand work as these are driven by individual customer requests. The company must respond to these requests and therefore these costs are non-discretionary.

In accordance with its distribution license, Hydro One is required to connect embedded generation customers, also known as distributed generation facilities ("DG"), as per the requirements of the Market Rules, the Distribution System Code ("DSC"), and all applicable codes, standards, and rules. Hydro One's investment plans are based on Ministry of Energy directives on DG and the Ontario Power Authority announcements and procurement windows for different Feed-in Tariff or FIT programs.

2.2 Planned Work

Planned work includes projects designed to increase or reinforce the capability of the existing distribution system, or to construct new lines and stations. System capability reinforcement investments are required to accommodate system load growth, to improve operational and asset life cycle planning or to improve system reliability. Hydro One is also obligated to undertake a prudent investment planning, prioritization and approval process to ensure continued capability of the existing system and to reliably supply customers in compliance with the DSC.

2.3 Prioritization of work

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 17, Schedules 1 to 6 has been completed for all development capital programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

Projects and programs under System Capability Reinforcement are reprioritized throughout the test years to ensure they are addressed in order of criticality. The urgency of investments that are driven by load growth are often dependent on future load forecasts and customer requirements. It is Hydro One's practice to assess and reprioritize projects each year as new loading information and updated forecasts become available. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding.

2.4 Summary of Development Capital

The net capital spending for 2015 to 2019 along with the spending levels for the bridge and historic years is provided in Table 1.

Table 1
Summary of Net Development Capital
($ Million)

Description	Historic				Bridge	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Connections, Upgrades	92.0	95.4	107.2	92.7	105.5	108.9	112.1	115.8	119.3	122.9
System Capability Reinforcement	49.3	45.9	56.7	70.0	61.1	81.4	71.5	83.2	62.0	74.2
Generation Connections	12.4	13.5	18.0	25.5	33.2	33.1	22.7	8.7	2.1	2.0
Wholesale Revenue Meters	9.3	2.4	4.0	3.9	0.4	0	0	0	0	0
TOTAL	**162.9**	**157.1**	**185.9**	**192.1**	**200.2**	**223.3**	**206.3**	**207.7**	**183.5**	**199.1**

The 2015 and 2016 spending is above historic levels but spending in 2017 to 2019 is in line with historic spending in more recent years. This is predominantly attributed to the following factors:

- The annual demand for new customer connections is expected to increase over the test years based on connection forecasts and spending increases accordingly;
- Spending on system capability reinforcement is higher in some years to account for investments required to maintain system integrity and for capital contributions from

- the Distribution business to fund new or enhanced Transmission facilities that are required to meet load growth on the distribution system. The costs are higher in 2017 than in the previously filed version of this exhibit to include the Leamington TS capital contribution of $22 million. This project is also called the Supply to Essex County Transmission Reinforcement project and a Section 92 application for this project was filed with the Board on January 22, 2014. More detail on this project is provided in Exhibit D2, Tab 2, Schedule 3, Reference # D-12; and
- Generation Connections spending has increased over the historical years as the amount of DG connecting to the system has increased and this levels off in 2014 and 2015. Spending decreases from 2016 to 2019 as the number of connections declines.

Additional details concerning these increases and a discussion of year over year variations in spending, where significant, are provided below.

3.1 New Connections, Service Upgrades and Metering

Investments are required for the connection of new customers to the system and service upgrades. As discussed in Section 2.1, these activities are considered demand work as they are driven by individual customer requests. The volume and funding levels of these programs in 2015 through 2019 are based on consideration of historical cost and volumes, and forecast of economic variables such as Ontario GDP and Ontario Building Permits. The Investment Summary Document ("ISD") for this program contain further details and may be found in Exhibit D2, Tab 2, Schedule 3. These customers are connected consistent with Hydro One Distribution's Conditions of Service. Customers may be required to make capital contributions in accordance with the Distribution System Code ("DSC").

The investments in Connection and Upgrades are categorized into:

(1) Customer Connections;

(2) Service Upgrades;

(3) Meter Purchases; and

(4) Service Cancellations

The actual and projected volume (number of units) of new Customer Connections, Service Upgrades, Service Cancellations and Cancellations from 2010 to 2019 is summarized in the Table 2(a) . The proposed funding for Customer Connections, Service Upgrades and their associated Meter Purchases for 2015 to 2019, along with the investment levels for the bridge and historic years are provided in Table 2(b).

Table 2(a)
Customer Connections, Service Upgrades and Service Cancellations
(Units)

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
New Connections	16,909	14,668	15.336	13,857	15,370	15,530	15,570	15,850	16,010	16,170
Service Upgrades	4,691	4,375	4,498	4,213	4,514	4,554	4,604	4,654	4,704	4,744
Service Cancellations	5,518	5,750	5,344	4,586	6,170	6,230	6,300	6,360	6,420	6,490

Table 2(b)
Customer Connections, Service Upgrades and Meter Purchases
($ Million)

Description	**Historic**				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customer Connections	71.4	70.2	78.2	68.5	79.6	82.1	84.6	87.4	90.1	92.8
Service Upgrades	20.3	20.1	23.0	20.0	18.4	18.9	19.6	20.2	20.8	21.4
Meter Purchases	0.3*	5.0	6.0	4.2	7.5	7.8	8.0	8.2	8.4	8.7
TOTAL	**92.0**	**95.4**	**107.2**	**92.7**	**105.5**	**108.9**	**112.1**	**115.8**	**119.3**	**122.9**

*Meter purchases in 2010 only included non-smart meter retail meters; for 2011 & 2012 smart meters purchased for new connections and upgrades were gradually included in the program. As of 2013, the cost of smart meters and network equipment for new connections and upgrades are funded under the normal Development Capital program, Meter Purchases.

3.1.1 Customer Connections

To comply with its obligations under section 28 of the *Electricity Act, 1998,* Hydro One Distribution is required to provide a connection service to new industrial, commercial, residential, and seasonal customers when requested. The division of costs between Hydro One Distribution and the customer is determined based on the Company's connection policies, which are in accordance with the DSC requirements. In response to the OEB's requirements, Hydro One Distribution has established service quality indicators to monitor the responsiveness of Hydro One Distribution to customers' requests for new connections.

Hydro One Distribution provides services for all aspects of a new connection. Activities include line layout, staking, installation of poles, conductor, transformers and meters, and property or other approvals required for any new Hydro One Distribution facilities. Customers located adjacent to a line are referred to as "lie along" customers, and under current connection policies, are not required to contribute to the connection cost for a standard type of connection. Customers requiring an upgrade to the "standard connection" pay for the incremental cost of these upgrades. Non-"lie along" customers requiring line extensions need to contribute to the cost of the connection as specified in the DSC.

The number of new connections in 2010 to 2013 varied from approximately 14,400 to 16,700 connections per year. The forecast values for 2015 to 2019 align with these historic values, varying from 15,530 to 16,170 connections annually. The forecast numbers reflect expected economic conditions and are consistent with the distribution load forecasting methodology set out in Exhibit A, Tab 16, Schedule 2.

3.1.2 Service Upgrades

To comply with its obligations under section 28 of the *Electricity Act, 1998*, Hydro One Distribution is required to respond to existing customers who require a larger service to accommodate additional load and/or modify their electrical service entrance. These costs are classified as upgrade costs. A service upgrade normally requires the replacement of secondary service wires and the preparation of a service design. Also, it may be necessary to upgrade transformer(s), replace meters or install additional transformers. For standard service upgrades, Hydro One Distribution will provide a service layout, pole-mounted transformer, and the meter installation, if required. Costs for service modifications that exceed the cost of a standard installation would be recovered from the customer on a user-pay basis. Hydro One Distribution's customer capital contribution policies adhere to Distribution System Code requirements.

Volumes of service upgrades for 2015 to 2019 are projected to be about 4,554 to 4,744 per year based on historic demand.

3.1.3 Meter Purchases

New meters are required for New Connections, and in some cases Upgraded services. Expenditures for these meters are shown in Table 2(b). This is an increase over recent historic years where the majority of the meters and network equipment used in new connections and service upgrades were smart meters, and funded under the smart meter program. Beginning in 2011, these costs were gradually covered under Connections and Upgrades, coinciding with the ramp down of province-wide smart meter installations. As of 2013, the cost of meters and associated network equipment installed for new connections and upgrades are funded under the normal Development Capital program, Connections and Upgrades.

3.1.4 Service Cancellations

For a variety of reasons, customers may want to disconnect from the distribution system. In these cases, Hydro One Distribution owned equipment is removed, and the remaining installation is left in a safe condition. Costs related to this customer-driven activity are classified as cancellations, and Hydro One Distribution bears the cost of the work involved. Removals of this type are accounted for under depreciation. The volume of Service Cancellations are expected to be in the range of 6,230 to 6,490.

3.1.5 Summary of New Connections and Upgrades Spending Requirements

The 2015 to 2019 investment requirements for new connections and upgrades range from $108.9 to $122.9 million, after deducting amounts contributed by the connected customers. The gradual increase in investment levels over the test years is due to the projected increase in volumes.

New connections are expected to incease from 15,530 units in 2015 to 16,170 units in 2019, resulting in net expenditures rising from $82.1 to $92.8 million during the test years. Likewise, upgrade volumes are projected to rise from 4,554 to 4,744, resulting in net expenditures increasing from $18.9 to $21.4 million annually. As meter purchases are required for these connections and upgrades, the projected investments for meter purchases also rises from $7.8 to $8.7 million over the test years. An Investment Summary Document ("ISD") which describes these investment in more details are provided in Exhibit D2, Tab 2, Schedule 3.

As Hydro One Distribution is required to respond to customer requests for new connections and upgrades, reductions in funding for these investments would result in non-compliance with Distribution license requirements and with obligations under the Distribution System Code.

3.2 System Capability Reinforcement

System Capability Reinforcement includes investments required to ensure the continued capability of the existing system to reliably supply customers in compliance with the Distribution System Code. In accordance with Section 3.3.1 of the Code, Hydro One Distribution continues to plan and build the distribution system for reasonable forecast load growth by performing enhancements to its distribution system, for purposes of improving system operating characteristics or for relieving system capacity constraints. Investments in System Capability Reinforcement provide for:

(1) new and modified distribution system facilities to accommodate increases in customer load;
(2) additions to the system that will improve operations and asset life cycle planning;
(3) system modifications and additions to improve system reliability; and

(4) capital contributions to support upgrades required to Ontario's Transmission Grid.

The net capital investment level for 2015 to 2019 along with the investment levels for historic and bridge years are provided in Table 3. System Capability Reinforcement investments were not grouped by the four categories listed above until 2014. Therefore Table 3 only provides detail by the four categories for 2014 onwards.

Table 3
System Capability Reinforcement
($ Million)

Description	**Historic**				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
System Capability Reinforcement	49.3	45.9	56.7	70.0						
Investments Driven by Load Growth					41.8	44.4	45.3	46.3	47.2	48.1
Investments to Increase Operational Efficiency/Asset Life Cycle Optimization					7.4	9.5	9.7	9.9	9.7	9.8
Investments to Improve System Reliability					2.7	2.7	2.8	2.8	2.9	2.9
Capital Contributions to New or Upgraded Transmission Facilities					9.2	24.9	13.6	24.1	2.2	13.3
TOTAL	**49.3**	**45.9**	**56.7**	**70.0**	**61.1**	**81.4**	**71.5**	**83.2**	**62.0**	**74.2**

The investments under System Capability Reinforcement are considered planned work as discussed in Section 2.2 above. As such, projects and programs within these four main categories under System Capability Reinforcement are reprioritized throughout the test years to ensure they are addressed in order of criticality.

The urgency for investments that are driven by load growth is often dependent upon future load forecasts and customer requirements. As these investments are based on load forecasts, it is prudence for the distributor to reprioritize projects each year as new loading information and updated forecasts become available. Certain projects may be expedited or deferred to address the changing needs of the distribution system.

When station or line assets are expected to exceed capacity within a period of time, an investment should be made to address this situation within a five year planning period. However, when new forecasts indicate that the capacity is exceeded outside the five year planning period, then projects may be deferred for more critical investments.

Investments are prioritized to increase operational efficiency/asset life cycle optimization and improve customer reliability. Many factors are explored through the prioritization process, including the condition of the assets; customer requirements within the area; and time frames for other associated capital or maintenance work in the area. Work "bundling", when possible, is done to take advantage of cost benefits that may be achieved and to minimize customer outage impacts. Changes to any of these factors, along with the emergence of new opportunities and risks as a result of new or updated information, can result in a variance to investment in-service dates.

3.2.1 Investments Driven by Load Growth

These system investments are required to accommodate regional load growth and demand for electricity. Each year there are approximately 20,000 new customer connections and upgrades made to the distribution system, ranging in size from 10 kVA residential services to services greater than 10 MVA for large customers such as mines or manufacturers. Load growth also occurs within Local Distribution Companies (LDC's) embedded within Hydro One's Distribution system. As these customer connections accumulate over time, system elements such as conductors, transformers, regulators, and switching elements must be monitored to ensure they are not operated over their maximum ratings during periods of high load. Areas on the system with heavily loaded elements are upgraded to avoid equipment damage or lengthy power interruptions to customers.

The impact of new connections to the distribution system is monitored through various processes. These activities include comparing the system load to capacity, carrying out six-year cycle studies on distribution feeders, system impact assessments, and field reported occurrences of substandard supply conditions. Hydro One Distribution uses a number of processes and tools to compare existing system conditions to established planning guidelines. These conditions include voltage levels, equipment loading, and protection coordination. Where several issues exist within a specific geographic area, a long term Area Supply study is conducted to determine the best overall solution for the area.

Hydro One's distribution system is monitored as detailed in the Development OM&A at Exhibit C1, Tab 2, Schedule 3 to ensure that conditions which pose potential threats to customer reliability and quality of power are addressed in a timely manner.

3.2.2 Investments to Increase Operational Efficiency/Asset Life Cycle Optimization

These investments involve addressing assets reaching their end of expected service life and improving the operational efficiency by upgrading or modifying the assets and the existing system. Instead of replacing station or line components with like-for-like replacements, there may be opportunities to improve operational efficiency, improve reliability, or reduce overall costs. This is particularly beneficial in areas where multiple issues are present. In these cases, system capability reinforcement is the preferred option to address asset sustainment needs. Examples of these types of projects include voltage conversions to eliminate distribution stations and improve system voltage performance, installing new supply points, or constructing feeders to transfer loads to a new transmission station to replace an existing station.

3.2.3 Investments to Improve System Reliability

These investments are required to ensure the long-term improvement of reliability performance and to minimize the impact of power interruptions to customers. While outages are inevitable due to the nature of the distribution system, reliability must be managed to meet customer expectations at a reasonable cost. Following industry standard indices, reliability is measured at a system-wide level using the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).

These investments involve system modifications or additions to improve reliability. Projects include installing loop-feeds to provide alternative supply capabilities, installing express feeders to critical supply areas and improving sectionalizing capabilities to minimize the impact of lengthy outages. These reliability investments typically occur in areas with a higher customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

3.2.4 Capital Contributions to New or Upgraded Transmission Facilities

Solutions to address a significant increase in distribution customer load may involve new transmission facilities. Hydro One Distribution's planning approach assesses alternatives in a comprehensive manner that includes consideration of both distribution and transmission alternatives, where appropriate, to arrive at the optimum long-term solution. When existing or forecasted load exceeds the capacity of existing transmission connection facilities, a long range Area Supply Planning study is conducted in conjunction with Hydro One Transmission Connection Planning. If existing or proposed connection capacity is shared between Hydro One Distribution and other LDCs, then a joint planning study may be required. In some cases, where transmission network capacity may be an issue, then a wider-ranging Regional Supply Study may also be required with the involvement of the Ontario Power Authority (OPA) and other LDCs. Details on the regional planning process are provided at Exhibit A, Tab 17, Schedule 8.

For investments which involve the addition or modification to a transmission facility, Hydro One Distribution is required to contribute to the cost of construction of transmission facilities as stipulated in the Transmission System Code (TSC). The amount of capital contributions for new or upgraded Transmission facilities can vary significantly from year to year, depending on the timing and scope of the construction of these facilities as well as the cost allocation methodologies mandated by the TSC.

Hydro One Distribution is also required to provide true-up payments to Hydro One Transmission to account for any differences between actual revenues and the forecasted revenue assumed in the original capital contribution calculations.

3.2.5 Summary of System Capability Reinforcement Investment Requirements

In order to maintain the integrity of Hydro One's distribution system, address system load growth and ensure reliable customer supply that complies with service quality standards, the 2015 to 2019 investment requirements range from $61.2 to $81.4 million for Capability Reinforcement Projects. The large range in annual levels is mainly due to fluctuations in capital contribution requirements for investments to the Transmission System. These types of investments vary from approximately $2 million in 2017 and 2018 to approximately $21 million in 2015. ISDs for projects greater than $1 million are contained in Exhibit D2, Tab 2, Schedule 3.

The increase in investment requirements relative to historic years are attributed to increasing needs identified by system planning studies, load flow analyses, and engineering and technical studies. The cost and duration of individual projects can vary significantly depending on the scope of work required, and historically project costs have ranged from $30,000 to over $5 million and varied in duration from two months to more than a year, although most of the projects are placed in-service in the same year as when the capital expenditures are made.

Reduced investment in this program would result in overloading of system components, causing power quality degradation, and an increased risk of substandard supply conditions with possible equipment failure. In turn, this would lead to customer disatisfaction and more frequent and longer duration interruptions. As well, there is a risk that system protection and co-ordination schemes may be adversely affected, resulting in equipment damage and potential worker and public safety hazard due to equipment not operating as designed.

3.3 Generation Connections

In accordance with its distribution license, Hydro One Distribution is required to connect embedded generation facilities, also known as distributed generation ("DG") facilities, as per the requirements of the Market Rules, the Distribution System Code ("DSC"), and all applicable codes, standards, and rules. Hydro One's investment plans are based on Ministry of Energy ("MOE") directives on DG and the Ontario Power Authority ("OPA") announcements and procurement windows for different Feed-in Tariff ("FIT") programs. The cost allocation requirements are as set out in the DSC. These determine the investments that are presented in this section.

The DSC divides DGs into five size categories: micro, capacity allocation exempt small, small, mid-sized and large. In Section 1.2 – Definitions, each of the five size categories is defined:

- Micro-embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 kW or less;
- Capacity allocation exempt small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line;
- Small embedded generation facility – an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1 MW or less in the case of a facility connected to a 15 kV or greater line;
- Mid-sized embedded generation facility – an embedded generation facility with a name-plate rated capacity of 10 MW or less and a) more than 500 kW in the case of a

facility connected to a less than 15 kV line; and b) more than 1 MW in the case of a facility connected to a 15 kV or greater line; and

- Large embedded generation facility – an embedded generation facility with a name-plate rated capacity of more than 10 MW.

Based on the DSC definitions, Hydro One Distribution classifies DGs into three categories for planning purposes: micro-embedded; capacity allocation exempt ("CAE"); and capacity allocation required ("CAR"), which includes large DGs, mid-sized DGs and small DGs that are not capacity allocation exempt.
On May 30th, 2013, the MOE announced a government directive (http://news.ontario.ca/mei/en/2013/05/ontario-working-with-communities-to-secure-clean-energy-future.html) regarding the OPA's small FIT and MicroFIT procurement. Under this directive, 70 MW of CAE DGs are to be procured under the Small FIT program and 30 MW of micro-embedded DGs are to be procured under the MicroFIT program. Thereafter, the annual Small FIT and MicroFIT program generation procurements for the years 2014 - 2018 is 150 MW and 50 MW, respectively. While these new procurements are planned for CAE and micro-embedded DGs, there is no additional procurement for CAR DGs under the FIT program. The lack of procurement for CAR DGs results in a downward trend in the investment forecast.

Based on experience with the previous FIT program, Hydro One's statistics show that around 34% of all CAE generation connection applications received by the OPA will be in Hydro One's service territory; and around 51% of all MicroFIT generation connection applications will be in Hydro One's service territory.

Given the lack of an OPA procurement target for CAR DGs at this time, the connection forecast for 2014 – 2019 consists of the existing contracted projects that will be connected in those years. For CAE and Micro-embedded DG the connections forecast includes the OPA procurement targets and the existing contracted projects that will connect in the 2014 – 2019 period. The total number of projects forecast for 2014 to 2019 is shown in Table 4.

Table 4
Forecast Number of Connections

DG Size Category	2014	2015	2016	2017	2018	2019
Capacity Allocation Required (CAR)	39	38	38	14	1	1
Capacity Allocation Exempted (CAE)	262	262	262	188	188	188
Micro-embedded	1600	1400	1200	1000	800	600

The proposed funding for these generation connection investments in 2014 to 2019 is provided in Table 5.

Table 5
Summary of Generation Connections Investments
($M)

DG size category	Investment	2014	2015	2016	2017	2018	2019
CAR	Connection Assets	-	-	-	-	-	-
CAR	Renewable Enabling Improvements	2.9	2.9	2.9	1.0	0.0	0.0
CAR	Expansion	15.8	15.8	15.8	5.5	0.0	0.0
CAE	Connection Assets	-	-	-	-	-	-
CAE	Renewable Enabling Improvements	1.6	1.7	1.4	1.2	1.3	1.3
CAE	Expansion	0.2	0.2	0.2	0.2	0.3	0.3
CAE	Net Metering	0.0	0.0	0.0	0.0	0.0	0.0
MicroFIT	Generation Connection	1.1	1.0	0.9	0.7	0.6	0.5
Total		21.7	21.6	21.2	8.7	2.1	2.0

For the CAR and CAE projects, the investments are broken down into three components: Renewable Enabling Improvements (“REI”), Expansions, and Connection Assets. The cost allocation for each component is based on Hydro One's connection policy and is in accordance with the DSC. Under the policy, Hydro One is responsible for all REI cost and for Expansions cost up to $90k per MW of the DG's rated capacity; and the generator is responsible for Connection Assets cost, and the remaining portion of Expansions cost above $90k per MW.

Direct Benefits

Consistent with the requirements of Regulation 330/09, a portion of the costs associated with the connection of renewable generators is allocated to Hydro One ratepayers and a portion of the costs are allocated to all Provincial ratepayers. The allocation of costs is explained in Exhibit F1, Tab 1, Schedule 3, Attachment 3.

The allocation of costs to Hydro One ratepayers and Provincial ratepayers is different for Expansion assets and for REI assets. Connection Assets are paid for by the generator customer. Tables 6 to 8 show the cost allocation breakdown for Connection Assets, Expansion Assets and REI Assets for both CAR and CAE projects.

Table 6
Cost Allocation Breakdown for Connection Assets of CAR and CAE Projects

	Connection Asset									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Project Count	30	97	159	140	301	300	300	202	189	189
MW	226.6	166.5	216.0	336.8	364.4	356.4	356.4	149.6	45.6	45.6
Generator Contribution ($M)	0.2	2.5	3.5	4.5	6.0	6.1	6.1	3.9	3.5	3.6
Hydro One Ratepayer Contribution ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Provincial Ratepayer Contribution ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gross Total ($M)	0.2	2.5	3.5	4.5	6.0	6.1	6.1	3.9	3.5	3.6
Net Total ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 7
Cost Allocation Breakdown for Expansion Assets of CAR and CAE Projects

	Expansion Asset									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Project Count	30	97	159	140	301	300	300	202	189	189
MW	226.6	166.5	216.0	336.8	364.4	356.4	356.4	149.6	45.6	45.6
Generator Contribution ($M)	0.5	5.9	7.4	10.7	7.5	7.5	7.5	2.8	0.2	0.2
Hydro One Ratepayer Contribution ($M)	0.7	1.2	2.5	3.1	2.9	2.9	2.9	1.0	0.0	0.0
Provincial Ratepayer Contribution ($M)	1.6	4.7	11.1	13.5	13.1	13.1	13.1	4.7	0.2	0.2
Gross Total ($M)	2.8	11.8	21.0	27.4	23.5	23.5	23.5	8.5	0.5	0.5
Net Total ($M)	2.3	5.9	13.6	16.7	16.0	16.0	16.0	5.7	0.3	0.3

Table 8
Cost Allocation Breakdown for REI Assets of CAR and CAE Projects

	REI Assets									
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Project Count	30	97	159	140	301	300	300	202	189	189
MW	226.6	166.5	216.0	336.8	364.4	356.4	356.4	149.6	45.6	45.6
Generator Contribution ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro One Ratepayer Contribution ($M)	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.1	0.1	0.1
Provincial Ratepayer Contribution ($M)	2.0	3.1	3.6	5.3	4.3	4.3	4.1	2.1	1.2	1.2
Gross Total ($M)	2.1	3.3	3.8	5.5	4.5	4.6	4.3	2.3	1.3	1.3
Net Total ($M)	2.1	3.3	3.8	5.5	4.5	4.6	4.3	2.3	1.3	1.3

For micro-embedded generation projects, the investment covers the connection and meter costs and the costs are paid by Hydro One ratepayers and the generator customers. There is no funding from all Provincial ratepayers for the micro-embedded generators. Hydro One follows the requirements for Distributors under the DSC for the work and assessments needed, including provision of an offer to connect. Based on historic values, on average 65% of the total project costs for micro-embedded connections are recoverable from the generators. A breakdown of the costs is shown in Table 9.

Table 9
Cost Allocation Breakdown for MicroFIT Projects

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Project Count	2189	5331	2375	1447	1600	1400	1200	1000	800	600
MW	19.2	50.2	22.6	13.3	15.0	13.2	11.3	9.4	7.5	5.6
Hydro One RatePayer Contribution($M)	3.7	3.2	0.8	0.7	1.1	1.0	0.9	0.7	0.6	0.5
Generator Contribution($M)	1.7	6.9	5.7	2.6	2.1	1.8	1.6	1.4	1.1	0.9
Total	5.4	10.0	6.4	3.3	3.2	2.8	2.5	2.1	1.7	1.3

Additional Costs Due to DG Connections

In addition to the capital investments presented above, Table 10 shows the investments for the efforts in mitigating excessive voltage fluctuation due to generators connecting at a distance from transformer stations ("Distance Limitation"); and over-voltage conditions due to Delta-Y generator transformer winding configuration ("Delta-Y Transformers") as set out in the Board's Decision in EB-2010-0229. These investments cover the cost to alleviate risks associated with poor feeder voltage performance and temporary over voltage. The Distance Limitation mitigation involves work to improve feeder voltage performance and is expected to be complete in 2015. The Delta-Y Transformers mitigation work involves installing grounding transformers at affected feeders and is expected to be complete in 2016. The completion of these mitigation efforts results in a significant drop in the investment forecast after 2015 and 2016.

Table 10
Investments based on OEB Decision Order EB-2010-0229
($M)

Investments	2014	2015	2016	2017	2018	2019
Delta- Y Transformers	2	2	1.5	-	-	-
Distance Limitation	9.5	9.5	-	-	-	-

3.4 Generation Connection Enhancements

In the 2010 and 2011 Distribution Rate Application, EB-2009-0096, Hydro One planned for Generation Connection Enhancement investments to enable government objectives to connect future renewable generation connections. The areas that were identified to facilitate the anticipated renewable generation connections included targeted enhancements to support DG; station upgrades for protection, control, and load rejection; feeder control infrastructure; and wholesale revenue metering modifications. However, the Generation Connection Enhancement work was not required due to the following sequence of events.

In 2009, the FIT program was launched. The program restricted DG connections to only those parts of the distribution and transmission systems with available capacity. Capacity availability was determined by the Transmission Availability Test (TAT) and Distribution Availability Test (DAT). Projects that failed TAT or DAT were placed in the FIT Reserve to be re-evaluated with an Economic Connection Test (ECT) at a future date. In 2011, the OPA began a 2-year review to evaluate the FIT program. In 2012, a new FIT program was launched based on the results of the FIT 2-year review. The new FIT program eliminated the FIT reserve and ECT from the previous FIT program. Due to this elimination, it became unnecessary to perform the additional generation connection enhancements. Going forward, a separate investment for these types of enhancements is no longer required as any system upgrades triggered by a generation connection project would be paid for under the investments for Expansions or REI.

OPERATIONS CAPITAL

1.0 INTRODUCTION

Operations capital investments are required to implement, enhance and modify the physical tools, systems and infrastructure used to operate the Hydro One distribution system. These investments provide performance improvements in the form of reduced outage duration, improved customer satisfaction, and accurate information for regulatory reporting as required by the Distribution System Code (DSC). They also deliver efficiency improvements to Hydro One Distribution's operating function and ensure that sustainment costs for tools, systems and infrastructure are minimized. Hydro One continues to be proactive in assessing and implementing emerging technologies to improve the management and operation of the distribution system.

This summary table illustrates the alignment of Operations investments to the outcome measures outlined in the OEB's Renewed Regulatory Framework for Electricity Distributors.

OEB Outcome	**Relevant References**	
Customer Focus	Section 2.0	Discussion
	Section 3.2	Network Outage Management System (NOMS)
	Section 3.6	Outage Response Management System (ORMS) Refresh
	Section 3.7	Integrated Voice Communications and Telephony System (IVCT) Refresh
Operational Effectiveness	Section 3.1	Operating Compute Refresh
	Section 3.2	Network Outage Management System (NOMS)
	Section 3.3	Operating Information Technology Facilities Refresh

OEB Outcome	**Relevant References**	
	Section 3.4	New Back-Up Control Centre (BUCC) Facility Development
	Section 3.5	Storage Area Network (SAN) Refresh
	Section 3.6	Outage Response Managemnt System (ORMS) Refresh
	Section 3.7	Integrated Voice Communications and Telephony System (IVCT) Refresh
Public Policy Responsiveness	Section 3.4	New Back-Up Control Centre (BUCC) Facility Development

2.0 DISCUSSION

Hydro One Distribution operates the assets of the distribution electric system and provides the dispatch function from the Ontario Grid Control Centre (OGCC). The OGCC is a shared facility which allows central operations of the distribution and transmission systems. The Back-Up Control Centre (BUCC) is located at separate site and is activated in the event the OGCC or its computer systems are rendered unavailable.

A suite of systems and tools is used to manage customer outage information in order to dispatch field crews, plan and schedule distribution outages, monitor and control the distribution system, and to provide distribution system performance statistics. As discussed in Operations OM&A section of the evidence filed at Exhibit C1, Tab 2, Schedule 4. These systems and tools include:

- the Outage Response Management System (ORMS);
- Interactive Voice Response (IVR);
- the OGCC Integrated Voice Communications and Telephony Systems (IVCT);
- the Provincial Mobile Radio System;
- the Network Outage Management System (NOMS);
- the Network Management System (NMS); and

- many other supporting systems and tools.

Operations systems at the OGCC and BUCC are mature installations which are functioning well and delivering their intended benefits. However, the Ontario government's renewable generation and conservation initiatives continue to have a major impact on distribution operations. Several major investments are needed to meet the challenge posed by these initiatives.

The Green Energy & Economy Act 2009 continues to drive the installation of renewable electricity generation within the distribution system. NMS functionality has been extended to allow monitoring of Distributed Generation (DG) facilities from the OGCC. An Advanced Distribution System (ADS) pilot project is providing the opportunity to test and verify the automated monitoring and control of the distribution system through a Distribution Management System (DMS) providing added security and reliability for the distribution system. See Exhibit D1, Tab 3, Schedule 5 for further details.

These initiatives will require enhancements to the suite of systems and tools used to receive customer outage information, document and convey distribution system conditions, dispatch field crews, plan and schedule distribution outages, monitor and control the distribution system, and to be a repository for distribution system performance information.

The majority of the planned investments for 2015 to 2019 are to maintain functional viability and lifecycle management of the Operations Information Technology (IT) systems. It is vital to ensure all IT systems and tools are within vendor support periods. These projects include:

- Operating Compute Refresh (ISD O01);
- Network Outage Management System (NOMS) Refresh (ISD O02);
- Operating Information Technology Facilities Refresh (ISD O03);
- Storage Area Network (SAN) Refresh (ISD O05);
- Outage Response Management System (ORMS also known as Outage Management System OMS) Refresh (ISD O06); and
- Integrated Voice Communications and Telephony Systems (IVCT) Refresh.

These projects are outlined in section 3.0 of this exhibit.

Lastly, an investment will be made in a new facility to replace the existing BUCC (ISD O04). The existing BUCC facility is more than forty years old. The design and infrastructure are no longer capable of sustaining and meeting modern control centre requirements and standards. The BUCC investment is required to address known deficiencies. The BUCC facility consists of the systems, tools and infrastructure that support the Control Room and back office Operating functions. This project is also outlined in section 3.0 of this exhibit.

Required spending for the test years along with the historic and bridge year spending are provided in Table 1.

Table 1

Operations Capital

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Operations Capital	**1.2**	**1.3**	**2.7**	**3.6**	**5.1**	**9.4**	**18.8**	**7.0**	**7.0**	**4.2**

- The 2012 increase from 2010 and 2011 spending levels was due to the Storage Area Network Upgrade and the Control Room Workstation Console Refresh investments.
- A portion of the increase from historical spending in 2013 is due to the BUCC restoration activities following a major summer flooding incident.
- Spending increases between the bridge and test years are largely attributed to two large capital investments. The BUCC New Facility Development (ISD O04) and the ORMS Sustainment projects (ISD O06) account for 74% of the Test years planned spending.
- Planned spending of $3.5 between 2018 and 2019 are attributed to the Power Distribution Unit (PDU) lifecycle replacements associated with OGCC computer room facilities refresh investment (ISD O03).

3.0 OPERATIONS PROJECTS

Specific projects planned for the test years are described in this section. Investment Summary Documents (ISDs) for projects with net capital expenditures over $1 million dollars per year can be found in Exhibit D2, Tab 2, Schedule 3.

The IT Architecture and Infrastructure projects are organized into two groups, Common, and Discrete. Both groups include hardware and software components. Common projects are shared between multiple “Discrete” applications such as ORMS, NOMS and the NMS. Common architecture provides added configuration and maintenance flexibility while increasing available capacity. The Common group is further organized into categories which include Display, Compute and Storage (illustrated in Table 2).

Table 2

Operating IT Architecture & Infrastructure		
	Common	***Discrete***
Display	Wallboard Display	
	Console Displays	
Compute	Workstation Console	
		Applications
	Database Servers	
Storage	Storage Area Network	
	Storage Archive	

The Common IT Architecture and Infrastructure projects include:

- Operating Compute Refresh; and
- Storage Area Network (SAN) Refresh.

The Discrete IT Architecture and Infrastructure projects include:

- Network Outage Management System (NOMS) Refresh;
- Outage Response Management System (ORMS) Refresh; and
- Integrated Voice Communications and Telephony System (IVCT) Refresh.

Non – IT Architecture and Infrastructure projects include:

- Operating Information Technology Facilities Refresh; and
- New Back-Up Control Centre (BUCC) Facility Development.

Table 3 provides a summary of the required Operating capital investments during the test years.

Table 3
Operations Capital ($ millions)

		2015	2016	2017	2018	2019
O1	Operating Compute Refresh	0.0	0.0	0.0	0.9	1.9
O2	NOMS Refresh	0.0	1.4	0.0	0.0	0.0
O3	Operating Facilities Refresh	0.0	0.0	0.7	2.1	1.4
O4	BUCC – New Facilities Development	0.5	9.4	5.2	2.9	0.0
O5	OGCC Storage Area Network Upgrade	0.0	0.0	1.2	1.2	0.9
O6	ORMS Refresh	8.0	8.0	0.0	0.0	0.0
	(IVCT) Refresh	0.9	0.0	0.0	0.0	0.0
	Total Operations Capital	9.4	18.8	7.0	7.0	4.2

3.1 Operating Compute Refresh

This investment provides funding for the lifecycle management of common Operations IT hardware and software, system architecture and infrastructure which support diverse systems and applications. Specifically, database servers and workstation consoles will be end-of-life and require lifecycle replacement beginning in 2018. This will maintain the viability of Operations applications such as ORMS, NOMS and other mission critical applications.

Costs for this investment are $2.8 million dollars between 2018 and 2019. For additional details please refer to ISD O01 in Exhibit D2, Tab 2, Schedule 3.

3.2 Network Outage Management System (NOMS) Refresh

NOMS is an essential tool for planning, scheduling, assessing and execution of distribution equipment outages. The current application "NOMS v2" was placed in-service in 2010. This investment will be used to replace hardware and software components of NOMS that are at end-of-life. This will maintain the efficiency and provide flexibility to manage distribution system outages in the best interest of Hydro One customers.

Costs of this investment are $1.4 million dollars in 2016. For additional details please refer to ISD O02 in Exhibit D2, Tab 2, Schedule 3.

3.3 Operating Information Technology Facilities Refresh

Operating Information Technology facilities provide for and are considered the foundation of all Operations IT infrastructure. These facilities include: physical space, HVAC (heating, ventilation and air conditioning) systems, electrical power supplies, connectivity and networking. Specifically, this investment will provide funding for the refresh and lifecycle management of common OGCC Operations facilities such as:

- Uninterrupted Power Supplies used to maintain constant power while transferring between primary and secondary sources;
- Computer Room Air Conditioners units are used to regulate computer equipment operating temperatures;

- Power Distribution Units used to manage and distribute computer room power; and
- IT Networking used for IT system connectivity and Control Room Workstations.

Costs of this investment are $0.7 million dollars in 2017, $2.1 million dollars in 2018 and $1.4 million dollars in 2019. For additional details please refer to ISD O03 in Exhibit D2, Tab 2, Schedule 3.

3.4 New Back-Up Control Centre (BUCC) Facility Development

The BUCC facility consists of the building, computer tools and systems that support Operations in the event of a partial or total loss of the OGCC. The strategy for this investment is to replace the existing BUCC facility with a new facility. This investment provides for growth and expansion to accommodate existing and future requirements of the Network Operating Division. Not proceeding with this investment will result in continued risk to the backup control centre functionality of the facility, systems and tools. There is also the possibility of total loss of control of the distribution system in the event the OGCC or its computer systems are rendered unavailable. This could affect system reliability and the safety of Hydro One and other Local Distribution Company field staff.

Costs of this investment are $0.5 million dollars in 2014, $0.5 million dollars in 2015, $9.4 million dollars in 2016, $5.2 million dollars in 2017 and $2.9 million dollars in 2018. For additional details please refer to ISD O04 in Exhibit D2, Tab 2, Schedule 3.

3.5 Storage Area Network (SAN) Refresh

The SAN provides a common data storage platform for Operations systems and applications including ORMS, NOMS and other mission critical systems. This investment will provide a refresh to, and lifecycle management of, IT data storage at the OGCC and BUCC facilities previously refreshed in 2012.

Costs of this investment are $1.2 million dollars in 2017, $1.2 million dollars in 2018 and $0.9 million dollars in 2019. For additional details please refer to ISD O05 in Exhibit D2, Tab 2, Schedule 3.

3.6 Outage Response Management System (ORMS) Refresh

ORMS is the critical outage management tool that was originally placed in-service in 2003. As typically occurs with software applications, the vendor is continuously upgrading the software and after a series of upgrades and version changes withdraws support for older versions. This was recognized in 2007, when a version upgrade to ORMS was undertaken. A lifecycle system renewal is planned to commence in 2014 to replace hardware and software system components. This is required to maintain and improve the efficiency and effectiveness of distribution system operations. Failure to proceed with this investment would result in increased risk of application failure. This will impact the ability of the Distribution Outage Management Center (DOMC) to centrally and effectively manage distribution system outages in the safest, most efficient manner. Further, failure of this tool will impact performance of all customer facing systems including the Outage Map which may result in a decrease to customer satisfaction levels.

Costs of this investment are $19.0 million dollars between 2014 and 2016. For additional details please refer to ISD O06 in Exhibit D2, Tab 2, Schedule 3.

3.7 Integrated Voice Communications and Telephony System (IVCT) Refresh

The IVCT is used in daily operations at the control centre. This mission critical system provides effective voice communication management between the control centre, Hydro One field staff, connected customers, and emergency services. The current system was placed in-service with the inception of the OGCC in 2003. This investment is required to mitigate the risk of a system failure as it has reached end-of-life due to technological obsolesces.

Costs for this investment are $0.9 million dollars for each year in 2014 and 2015.

CUSTOMER SERVICE CAPITAL

1.0 INTRODUCTION

As stated in the Report on Renewed Regulatory Framework for Electricity Distributors (dated October 18, 2012), reiterated in the Board's Supplemental Report on Smart Grid (dated February 11, 2013), and discussed in the Long Term Energy Plan (dated December 2, 2013) smart grid development and implementation activities will be a central focus of the effort to incent innovation; particularly given the importance of grid-enhancing advanced technology systems and equipment for network modernization. Hydro One is continuing with its smart grid pilot project. Table 1 shows the expenditures.

Table 1
Customer Service Capital
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Smart Grid Project	18.4	30.1	43.1	6.4	22.9	22.5	9.9	3.9	0.0	0.0

Hydro One first developed its five-year plan (2010-2014) for its smart grid investments in the Green Energy Plan in its Distribution Cost of Service filing (EB-2009-0096). Hydro One has extended the timeline for these investments through to 2017. This extension accommodates the broad scope of work, evolving technologies, and the state of the market for these technologies. The 2013 expenditures were less than anticipated because the project team required more time to validate the smart grid technologies and processes before proceeding with investments. This reduced expenditure is reflected in Exhibit F1, Tab 1, Schedule 3, Attachment 4 (Disposition of the Smart Grid Variance Account). The overall expenditures are still expected to be within the same envelope as stated in EB-2009-0096.

Table 1.1 is a summary table detailing how the investments set out in this exhibit promote the four key outcomes outlined in the OEB's Renewed Regulatory Framework for Electricity Distributors.

Table 1.1: Customer Service Capital and RRFE Outcomes

OEB Outcome	**Relevant References**	
Customer Focus	Section 2.0	Smart Grid Projects
Operational Effectiveness	Section 2.0	Smart Grid Projects
Public Policy Responsiveness	Section 2.0	Smart Grid Projects

2.0 SMART GRID PILOT PROJECTS

In the Supplemental Report on Smart Grid issued on February 11, 2013, the Ontario Energy Board ("the Board") concluded that the objectives in the Minister's Directive (November 23, 2010) are aligned with the objectives of the Renewed Regulatory Framework. The Board also outlined guidance and expectations for distributors in relation to the establishment and implementation of a smart grid within the parameters of three objectives set out in the Minister's Directive: (i) Customer Control, (ii) Power System Flexibility and (iii) Adaptive Infrastructure.

The first key outcome the Board identified as appropriate for distributors was Customer Focus. This includes understanding customers' preferences when it comes to smart grid, educating customers on the opportunities presented by the technology, and facilitating customer access to their consumption data. Hydro One is continuing its Demand Response pilot, where it will enrol customer-owned devices into Hydro One's demand response programs on a trial basis. This will provide the system additional demand response capacity and will provide customers with new tools to manage their usage.

The Board also established an Operational Effectiveness outcome to closely align with the Power System Flexibility objective in the Minister's Directive. The Board expects distributors to demonstrate how they have incorporated investments that facilitate the integration of distributed generation and complex loads (e.g. customers with self-generation and/or storage capabilities). To meet this objective Hydro One will complete its Energy Storage Integration pilot. In addition, Hydro One will also make upgrades to the Distribution Management System, that will enable more selective load shedding during emergency bulk electric system events. Currently, all the energy from distributed generation would be lost during a load shedding event. These initiatives will aid in maintaining critical loads as well as maintaining much-needed distributed generation during periods of generation supply constraints by performing shedding at the distribution station or feeder section level.

The Board's third key outcome relates to the Adaptive Infrastructure objective in the Minister's Directive, including investigating opportunities for operational efficiencies and improved asset management as well as leveraging the data provided by smart grid technology. Hydro One will continue its pilot of Conservation Voltage Reduction, used to flatten and lower the overall voltage profile of feeders to reduce energy usage by customers. This, along with the Online Operating Diagrams, and Mobile Solutions, will yield operational and asset management efficiencies. The Demand Response for Operations will dispatch distribution generation in concert with real-time dispatchable loads (i.e. heating, cooling, electric vehicle, commericial) to optimize the distribution system.

Details of Hydro One's Smart Grid projects for 2015 to 2017 based on the Board's guidance on these objectives may be found in Table 2.

Table 2

Smart Grid Pilot Projects (2015-2017)

Supplemental Report on Smart Grid Objectives	Project	Scope of Work	Expected Benefit	Forecasted Expenditures ($M) 2015 Capital	2016 Capital	2017 Capital	In-Service Year
Customer Control • Understand customers preferences • Provide information and education to customers • Facilitate customer access to consumption data	Consumer Research	Perform customer research to understand customer preferences and determine which smart grid technologies would be most beneficial for customers.	Obtain intelligence on customer preferences that will feed the requirements and design of the smart grid initiatives.	0.0	0.0	0.0	Annual
	Demand Response	Enable home energy management systems for Hydro One customers and make customer data securely available to third party applications (i.e. smart phone apps)	Help customers understand, control and reduce their electricity charges and enable more peak shaving capacity.	3.0	0.0	0.0	2015
Power System Flexibility • Facilitate integration of distributed generation • Facilitate integration of complex loads (e.g. customers with self-generation and/or storage capabilities	Distribution Management Systems Enhancements	Enable new functionality of the DMS system by upgrading the system to version 3.5. This includes functionality for the power line maintainers (mobile DMS functionality), network operators and management of complex distribution network changes.	Provide further integration of smart grid capabilities into the central control system for operators.	7.7	0.0	0.0	2015
	Energy Storage Integration	Pilot both battery and flywheel energy storage technologies and integrate into DMS.	Incorporate energy storage into distribution operations to provide voltage regulation and absorb excess energy to integrate DG more effectively.	0.0	0.0	0.0	2015
	Network Model Build	Accurately model the distribution system in the Geographic Information System and other source systems to support smart grid applications.	Enable the use of the DMS and other applications to aor the province and the resulting benefits associated with DMS-support smart grid business capabilities.	1.5	0.5	0.0	2016
	Distributed Generation Dispatch	Pilot dispatch (on/off/up/down) of both small and large distributed generators ("DGs").	Provide operational control of DGs for both local planned outages as well as avoidance of surplus base load generation at the system level.	0.0	2.0	0.5	2017

Supplemental Report on Smart Grid Objectives	Project	Scope of Work	Expected Benefit	Forecasted Expenditures ($M) 2015 Capital	2016 Capital	2017 Capital	In-Service Year
	Selective Load Shedding	Upgrade the Distribution Management Software to enable load shedding at the Distribution Station and feeder section level.	Enables more surgical load shedding during bulk electric system emergencies that would maintain distributed generation and critical loads (hospitals, water treatment plants, etc).	0.0	0.4	0.0	2016
	Validation of Smart Grid Technologies and Processes	Conduct technical, operational and economic validation of all of the Phase 1 delivered technologies.	Allow for planning the eventual smart grid deployment programs, ensuring prudent investments for Hydro One customers.	1.0	0.5	0.5	All
	Infrastructure Support	Other ancillary project support functions such as communications, program management, process design and training development.	Support the delivery of individual projects.	1.8	1.3	0.2	All
Adaptive Infrastructure • Investigate opportunities for operational efficiencies • Investigate opportunities for improved asset management • Leverage the data provided by smart grid technology	Advanced Metering Infrastructure for Operations	Enhance outage management system to utilize the real time power outage notifications from customer smart meters and provide the ability to confirm outages to the control centre.	Improve time to restore outages and improve efficiency handling trouble calls.	1.3	0.0	0.0	2015
	Conservation Voltage Reduction	Pilot flattening and lowering voltage profiles on feeders to reduce losses on lines and energy use by consumers.	Reduce customers' energy consumption and manage voltage issues associated with DG and lower the line loss adjustment charged to customers.	0.2	0.0	0.0	2015
	Energy Theft & Analytics	Build an analytical system that examines meter and operational data to identify energy theft.	Identify and reduce energy theft, lowering the line loss adjustment charged to customers.	1.3	0.0	0.0	2015
	Operational Data Store & Analytics	Build a system that relates operational data with other data (meter, asset, customer, etc.) and provides an ability to perform analytics against the integrated "big data" set.	Provide new insights into asset condition and improve asset management decision making.	3.0	0.0	0.0	2015

Supplemental Report on Smart Grid Objectives	Project	Scope of Work	Expected Benefit	Forecasted Expenditures ($M) 2015 Capital	2016 Capital	2017 Capital	In-Service Year
	Online Operating Diagrams	Upgrade the Distribution Management System with the application to produce operating maps and diagrams.	Reduce the cost of printing and distributing paper maps and diagrams and ensure that field crews have the most up to date information.	0.0	0.5	0.0	2016
	Mobile Systems	Upgrade the Distribution Management System with new functionalities to enable mobile work forces.	Equip field crews with new mobile systems they can use to restore power more quickly and execute planned outages more efficiently.	0.0	1.0	1.0	2017
	Demand Response for Operations	Pilot a system that optimizes electricity load and supply on a local basis leveraging all of the variable load (electric vehicle, energy storage, residential/commercial demand response) and generation (dispatchable renewable, energy storage) available.	Integrates electric vehciles without impacting reliability as well as increases overall load capacity factor of the distribution system.	0.0	2.4	1.5	2017
	Infrastructure Support	Other ancillary project support functions such as communications, program management, process design and training development.	Support the delivery of individual projects.	1.8	1.3	0.2	All
	PROJECT TOTALS			**22.5**	**9.9**	**3.9**	

SUMMARY OF CORPORATE COMMON COSTS CAPITAL

Capital expenditures under the Corporate Common Costs program support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such, they consist of assets that are largely shared by both the Transmission and Distribution businesses. Corporate Common Costs include information technology (IT) installations such as applications software and computer equipment, buildings, office equipment, transportation and work equipment ("T&WE"), tools, and service equipment.

Table 1 provides a summary of the Distribution portion of the Common Corporate Costs Capital over the Historic, Bridge and Test years.

Table 1
Corporate Common Costs & Other Capital Allocated to Distribution 2010-2019
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Information Technology	18.9	26.1	19.4	13.4	29.8	22.6	20.1	22.9	17.6	18.6
Cornerstone Initiative	8.3	49.6	67.8	47.6	8.7	0.0	0.0	0.0	0.0	0.0
Facilities & Real Estate & Station Security Upgrades	14.9	22.1	13.0	10.2*	19.9	19.0	15.3	15.4	17.7	17.7
Transport & Work, and Service Equipment	51.1	36.3	39.9	43.5	51.4	43.8	49.1	44.8	48.9	46.1
Other (including Distribution Line Loss and CDM)	0.0	-1.1	2.4	-2.9	0.0	0.0	0.0	0.0	0.0	0.0
Total	**93.2**	**133.0**	**142.5**	**111.8**	**109.9**	**85.4**	**84.5**	**83.1**	**84.2**	**82.3**

*An absence of suitable properties for new facilities hampered the execution of the 2013 field facilities capital program.

Exhibit C1, Tab 5, Schedule 3 outlines the appropriate cost drivers that have been utilized to derive the Distribution allocation of this capital.

The level of spending in Information Technology capital for the test years is consistent with the levels of spending in the historical and bridge years. Exhibit D1, Tab 3, Schedule 7 details the capital requirements for Information Technology.

The Cornerstone initiative has been a major business transformation initiative in the historical and bridge years; it deals with end of life replacement of enterprise systems and also provides a platform for further effectiveness and efficiency gains at Hydro One. The capital spending for the Cornerstone project will be completed in 2014, which includes the new CIS system that was placed in service in 2013.

The primary driver for the spending in Facilities and Real Estate is the need to provide suitable space to accommodate staff and equipment required to handle the growth in Sustaining, Development and Operations work programs over the test years. Exhibit D1, Tab 3, Schedule 8 details the capital requirements for Facilities and Real Estate.

The decrease in Transportation & Work Equipment spending in 2015 from the bridge year is related to the stabilization in work programs for the Electro-Forestry Journey Person Program, the Forestry and Provincial Lines Apprenticeship Program and the helicopter replacement schedule. Overall spending in the test years rises slightly with funding increases in 2016 and 2018 driven by the helicopter replacement schedule. Service Equipment spending decreases from 2014 to 2019 as capital requirements for replacing specialized equipment decreases and Health, Safety and Environmnet costs for automated external defibrillators also decreases. Exhibit D1, Tab 3, Schedule 9 details the capital requirements for T&WE and Service Equipment.

The following table provides an overview of the various cost categories for the period 2010 through 2019, highlighting the total capital spending for Corporate Common Costs.

Table 2
Total Corporate Common Costs & Other Capital
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Information Technology	51.9	108.6	116.9	83.9	72.1	43.4	42.7	44.0	37.2	35.8
Facilities & Real Estate & Station Security Upgrades*	36.0	29.8	24.7	17.5	48.2	47.9	40.0	40.0	45.2	45.4
Transport & Work, and Service Equipment	68.3	49.5	54.2	62.3	74.3	63.6	70.4	64.6	69.9	66.0
Other (including Distribution Line Loss and CDM)	-0.2	-2.6	-12.3	-2. 9	0.0	0.0	0.0	0.0	0.0	0.0
Total*	**155.8**	**185.3**	**183.5**	**160.9**	**194.6**	**154.8**	**153.1**	**148.6**	**152.2**	**147.1**

*Figures changed to include transmission security infrastructure investments, which were previously classified as sustaining capital.

Table 3 describes how the investments summarized in this exhibit (and detailed further in Exhibits D1, Tab 3, Schedules 7-9) promote the four key outcomes outlined in the OEB's Renewed Regulatory Framework for Electricity Distributors.

Table 3: Corporate Common Costs Capital and RRFE Outcomes

OEB Outcome	Relevant References	
Customer Focus	Ex. D1-03-07, Sections 4.3, 4.6	Common Corporate Costs Capital – Information Technology - e-Customer Self-Service Replacement - Customer Experience Enhancement
Operational Effectiveness	Ex. D1-03-07 All sections	Common Corporate Costs Capital – Information Technology
	Ex. D1-03-08 All sections	Common Corporate Costs Capital – Facilities and Real Estate and Station Security Infrastructure
	Ex. D1-03-09 Sections 2.0, 3.0	Common Corporate Costs Capital – Transport, Work and Service Equipment - Transport and Work Equipment - Service Equipment
Public Policy	Ex. D1-03-07	Common Corporate Costs Capital – Information Technology

Responsiveness	Section 3.4	- Smart Grid
	Ex. D1-03-08 Section 2.1	Common Corporate Costs Capital – Facilities and Real Estate and Station Security Infrastructure - F&RE Capital Expenditures: Some new facilities requirements are driven by legislation, as described in Exhibit D2, Table 2, Schedule 3, investment summary document C02.
	Ex. D1-03-09 Section 2.1	Common Corporate Costs Capital – Transport, Work and Service Equipment - Transport and Work Equipment: Investment in twin engine helicopters to respond to increased restrictions by Transport Canada on single-engine flights.
Financial Viability	Ex. D1-03-08 Section 3.0	Common Corporate Costs Capital – Facilities and Real Estate and Station Security Infrastructure - Security Infrastructure: Investments in security to reduce theft and risk of legal claims by injured persons protect the financial viability of the business.
	Ex. D1-03-07 Section 4.0	Common Corporate Costs Capital – Information Technology - Development Projects: Investments promote efficiencies which yield savings that should be sustainable.

COMMON CORPORATE COSTS CAPITAL - INFORMATION TECHNOLOGY

1.0 OVERVIEW

Information Technology ("IT") refers to computer systems (hardware, software and applications) that support business processes used by employees throughout Hydro One. IT infrastructure includes the voice and data telecommunication networks; data centre installations; and computer equipment (servers, computers, data storage devices, and printers). Staff access software applications and systems from offices, field locations and mobile devices using Hydro One's wide area network, local area networks or through Hydro One's virtual private network.

IT capital expenditures include hardware and software for projects and programs that each in total cost more than $1 million. IT investments are made in accordance with approved business strategies and as part of the overall business plan. Exhibit D1, Tab 3, Schedule 6 (Summary of Corporate Common Costs Capital) describes which RRFE outcomes are promoted by the investments set out in this Exhibit.

Table 1
Total IT Capital Expenditures
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Hardware/Software Refresh & Maintenance	6.6	14.4	13.8	13.7	13.0	12.0	11.2	10.1	10.1	10.1	5.6	5.2	4.7	4.7	4.7
Minor Fixed Asset Program	14.6	17.4	14.5	12.2	19.8	17.4	19.5	17.8	14.6	14.2	7.9	8.8	8.0	6.6	6.4
Development Programs	11.5	6.1	9.1	4.3	20.5	14.0	12.0	16.1	12.5	11.5	9.1	6.1	10.1	6.4	7.5
Cornerstone	19.2	70.7	79.5	53.7	18.8	-	-	-	-	-	-	-	-	-	-
Total	**51.9**	**108.6**	**116.9**	**83.9**	**72.1**	**43.4**	**42.7**	**44.0**	**37.2**	**35.8**	22.6	20.1	22.8	17.7	18.6

Capital IT expenditures are undertaken as projects or programs to meet business requirements. Capital expenditures fall into 3 categories:

1.1 Hardware/Software Refresh and Maintenance

Hardware/Software Refresh and Maintenance programs ensure continued operations of the installed IT application infrastructure, and include costs related to upgrading existing systems.

1.2 Minor Fixed Assets (MFA)

Minor Fixed Assets (MFA) programs ensure the continued operations of the installed IT hardware infrastructure. Expenses in this category address equipment needs generated by the growth in demand for IT services, capacity limitations and the replacement of end-of-life IT equipment and in the Telecom network and Data Centers. MFA includes desktop/notebook computing equipment, field tablet computers, mainframe and storage devices, servers and peripherals, and telecommunication infrastructure including switches, computer-telephony interfaces, etc.

1.3 Development Programs

Development Programs ensure the replacement and/or upgrade of end-of-life applications and include investments in new applications to meet business objectives. Replacement of applications occurs when applications have become inadequate for current functional needs; where the platform is no longer supported by the vendor; to address legislative changes or market driven initiatives; or to significantly modify the application to better support an evolving business capability. New applications are added to address business needs and to support existing or new business processes.

Hydro One has established general architecture principles for all of its applications. These are:

- Applications will be "off the shelf" and will be maintained in a vendor supported version;
- Existing custom applications will be migrated to "off the shelf" solutions wherever possible;
- There will be fewer applications rather than more; and
- Middleware, such as Oracle's enterprise service bus, will be used as appropriate to facilitate application interconnectivity. Hydro One has already invested in creating this middleware or Service Oriented Architecture (SOA) to enable data integration within and between applications.

The major planned IT capital projects which will be funded in 2015 to 2019 are described below.

2.0 HARDWARE/SOFTWARE MAINTENANCE AND REFRESH PROGRAMS

Table 2
Hardware/Software Refresh and Maintenance Program Capital Expenditures
($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Hardware/Software Refresh & Maintenance	6.6	14.4	13.8	13.7	13.0	12.0	11.2	10.1	10.1	10.1	5.6	5.2	4.7	4.7	4.7
Total	**6.6**	**14.4**	**13.8**	**13.7**	**13.0**	**12.0**	**11.2**	**10.1**	**10.1**	**10.1**	5.6	5.2	4.7	4.7	4.7

Hydro One utilizes approximately 875 business software applications in order to equip its employees with the required technologies to perform their work functions. The software refresh and maintenance program provides the needed software vendors' releases, periodic version upgrades, and replacements of activity-focused applications.

Software and Applications are replaced or upgraded to ensure they remain compatible with current IT platforms and other interfacing applications. In this manner, vendor support is maintained to help fix breakdowns or other issues that may occur with the application. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

Included in 2015 through 2019 planned costs are the implementations of enterprise resource planning applications and tools, further IT security access control and monitoring capabilities, middleware and databases and productivity tools, server upgrades to keep data center infrastructure vendor supported and improvements to the disaster recovery platforms. Costs stabilize in 2015-2019 and there are no increases in costs to support the Hardware/Software Refresh & Maintenance program.

3.0 MINOR FIXED ASSETS

Minor Fixed Asset investments include specific programs to refresh aging hardware such as personal computers, servers and storage. Equipment is refreshed based on its age and the nature of the applications running on the hardware. Equipment may be upgraded, or improvements may be made to extend hardware lifecycle. Hydro One's strategy is to minimize the costs of ownership, ensure operations risk is kept at an acceptable level, and to maintain function and security. Planned funding is based on equipment lifecycles. This work is broken down into the categories shown in Table 3.

Table 3
Minor Fixed Asset Program Capital Expenditures
($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Servers and Storage	5.9	9.1	9.4	3.4	7.6	7.1	9.3	8.0	5.3	5.3	3.2	4.2	3.6	2.4	2.4
IT Desktops, Laptops, Tablets, Printers and Plotters	5.5	6.1	3.2	4.8	8.4	5.6	5.3	5.3	4.5	4.0	2.5	2.4	2.4	2.0	1.8
Telecom Infrastructure	3.2	2.2	1.9	4.0	1.8	2.7	2.9	2.5	2.8	2.9	1.2	1.3	1.1	1.3	1.3
Smart Grid[2]					2.0	2.0	2.0	2.0	2.0	2.0	0.9	0.9	0.9	0.9	0.9
Total	**14.6**	**17.4**	**14.5**	**12.2**	**19.8**	**17.4**	**19.5**	**17.8**	**14.6**	**14.2**	7.9	8.8	8.0	6.6	6.4

[2] MFA costs associated with the Smart Grid Program moved into IT starting 2014

3.1 Servers and Storage

This investment is required to respond to and manage annual growth in demand for additional IT processing and storage capacity and to address end of life issues with the existing Unix and Wintel servers.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support-life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time. In determining when systems require replacement, the functionality and operating and maintenance costs are assessed. Hardware upgrades are needed to maintain reliable service for business applications.

The funding for the servers and storage refresh program varies year to year depending upon hardware lifecycles and business requirements for increased processing capacity.

Costs in 2013 are low and increase in 2014 and 2015 as capital work programs requiring hardware purchases were deferred due to the scheduled 2013 implementation of the SAP Customer Information System Capital project. Costs are higher in 2016 and 2017 to accommodate typical lifecycle refresh of end of life storage hardware. Costs stabilize in 2018 and 2019.

3.2 IT Desktops, Laptops, Tablets, Printers, and Plotters

Desktop and laptop computers are used by most Hydro One staff for office productivity applications such as email, word processing, spreadsheet, presentation, and for business applications. Rugged tablet computers are used by field staff. Tablets are used with Geospatial Information Systems ("GIS") applications for undertaking system design work and for asset condition assessments. Plotters are used by Hydro One engineering and operations staff for design work and to plot system maps.

Hardware upgrades are required to accommodate new software requirements, to replace end of life equipment, to address warranty considerations and to maintain hardware reliability.

Equipment refresh maintains or reduces maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty. Hydro One's practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. In practice, the refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

The funding for desktops, laptops, tablets, printers, and plotters varies year to year depending upon hardware lifecycles, and business needs. Costs also include the purchase of semi rugged tablets for the Mobile IT development project. Costs stabilize in 2015 through 2019.

3.3 Telecom Infrastructure

The telecom assets of Hydro One are varied and have a large range of install dates and lifecycle dates. The business telecom network is used to transmit data required to run business applications. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Projects regularly undertaken include rewiring local area networks, replacing end of life data network switches and routers, upgrading voice infrastructure, replacing un-interruptible power source systems, and upgrading the security solutions for external network interfaces.

The investment in Networks for voice and data is undertaken to replace end-of-life assets and to maintain service reliability and security. The strategy is to replace equipment that is no longer supported by vendors. For network equipment the refresh occurs about every five years for voice and data network related hardware. The funding for voice and data networks varies year to year depending upon hardware lifecycle refreshes, and business needs for increased bandwidth. Costs in 2014 were low as the refresh program was accelerated into 2013. In 2014, major investment in Infrastructure was made to ensure Telecom data and a voice system was in place to support disaster recovery and voice unified communication. Costs stabilize in 2015 through 2019 for normalised refresh program covering Voice Networks, Telecom Networks, Data Centers and Perimeter Security.

3.4 Smart Grid

To support the investment in the Smart Grid program there is also necessary investments in server infrastructure to support the applications and tools required to manage and monitor the Grid. These infrastructure costs have been moved to IT starting in 2014.

4.0 DEVELOPMENT PROJECTS

In support of the business technology roadmap, Development Projects deliver expanded business capability through the introduction of new enabling technologies as well as protecting our current technology investments by addressing end of life replacements of business applications. The business technology roadmap identifies the sequencing and timing of key IT projects and the spend in each year varies in line with that overall strategy. Costs for IT development projects are detailed in Table 4. Efficiencies yielded by some of these projects are detailed in Exhibit A, Tab 19, Schedule 1.

Table 4
IT Development Projects Capital Expenditures
($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Field Workforce Optimisation	0.0	0.0	0.0	0.0	9.5	5.0	5.0	5.0	2.0	2.0	2.3	2.3	2.3	0.9	0.9
Enterprise GIS Program	3.1	2.5	5.7	4.3	1.0	2.0	1.0	2.1	0.0	1.0	0.9	0.5	1.5	0.0	1.0
eCustomer Self-Service Replacement[3]	1.1	0.0	0.0	0.0	3.0	2.0	0.0	3.0	0.0	2.0	2.0	0	3.0	0.0	2.0
CTI Replacement[3]	0.0	0.0	0.0	0.0	5.0	2.0	0.0	0.0	1.0	0.0	2.0	0.0	0.0	1.0	0.0
Enterprise Analytics	0.0	0.0	0.0	0.0	0	2.0	2.0	2.0	0.0	0.0	0.9	0.9	0.9	0.0	0.0
Customer Experience[3]	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	0.0	1.0	1.0	1.0	1.0	0.0	1.0
Corporate Support Optimization	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	3.0	0.0	0.0	1.4	0.0	1.4	0.0
Mobile IT	3.6	2.2	3.4	0.0	1.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	1.4	0.0	0.0
Engineering Design Transformation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	3.0	0.0	0.0	0.0	1.9	1.4
Information Rights	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0	0.0	1.2	1.2

Description	**Historical Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Management															
Warehouse Bar Coding	1.1	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HST Implementation	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dx Asset Information[3]	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**11.5**	**6.1**	**9.1**	**4.3**	**20.5**	**14.0**	**12.0**	**16.1**	**12.5**	**11.5**	9.1	6.1	10.1	6.4	7.5

[3] These projects are Hydro One Distribution related only

4.1 Field Work Force Optimization

A mobile strategy has been developed to create efficiencies for our field worker employees. There are several components that make up this strategy. This project will span 2014 through 2019 and will streamline Hydro One work management processes and deliver an enhanced, integrated Scheduling and Dispatching Mobile solution. All required work information will be surfaced through SAP's latest platform SAP Mobile Platform (SMP). It will simplify and rationalize the handling of work orders for field asset maintenance, inspections and defect reporting across the LOBs. The objective is to present the asset condition data to the field worker to be able to make decisions in the field rather than wait until they return to the office. Through this initiative, the synchronization of work orders will also trigger the download of relevant Hydro One Document System (HODS) documents. The intent is to allow users in the field to use HODS as reference material to assist them in following proper safety procedures when collecting measurements on high voltage equipment. Additionally, the mobile solution will include work execution and status update as well as time reporting. It will also decommission a number of existing mobile applications that have either reached end of life or no longer meet business requirements.

4.2 Enterprise GIS Program

Geospatial technology is a key infrastructure that enables a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. Geospatial technology and the underlying connected network model is also a key component required to support the benefits achieved from smart grid initiatives.

Existing investments in the Enterprise GIS Program have enabled the integration of SAP and GIS achieving a synchronized, composite asset register, including distribution and transmission assets, comprised of Hydro One's major asset management systems. As part of the Final Destination initiative, spatial data repositories and related business processes across Hydro one were consolidated. The GIS Upgrade was deployed in December 2013. This project in 2015 through 2017 will help build additional capital improvements. In 2017, there will be an upgrade to the keep the investment in Enterprise GIS vendor supported and meet Hydro One requirements. In 2019, an investment is required to improve and enhance the technologies required for Data quality and Network models.

4.3 eCustomer Self-Service Replacement

This project is a complete re-design of how we interact with our customers online. Currently Hydro One leverages a customer portal for customers to access account information details and history. While a secure portal for customers to access is an important part of the experience, it is also important that we become more accessible, turn around inquiries quickly, and more effectively direct customers to the correct resource for resolution via capabilities such as “Live Chat”. Improved analytics can be used to anticipate customer needs and update FAQ pages with the end goal being a lower overall cost of interacting with customers while providing a better customer experience.

4.4 Computer Telephony Integration (CTI) Replacement

Computer telephony integration is used at Hydro One for:

- Call information display (caller's number (ANI), number dialed (DNIS), and Screen population on answer, with or without using calling line data;
- Automatic dialing and computer controlled dialing (fast dial, preview, and predictive dial.);

- Phone control (answer, hang up, hold, conference, etc.);
- Coordinated phone and data transfers between two parties (i.e. pass on the Screen pop with the call);
- Call center phone control (logging on; after-call work notification);
- Advanced functions such as call routing, reporting functions, automation of desktop activities, and multi-channel blending of phone, e-mail, and web requests;
- Agent state control (for example, after-call work for a set duration, then automatic change to the ready state); and
- Call control for Quality Monitoring/call recording software.

Our current CTI platform requires replacement to accommodate tighter integration between CTI and our work force scheduling technologies. The project will make the CTI an integrated multi-channeled solution so that we will be able to keep up with the demands of the customers and their preferred channel of interaction. This new integration will allow calls to be routed, scheduled and dispatched in a more efficient manner with the end result being better customer service. It will also allow us to scale up in a cost effective way in the event of a natural occurring disaster such as storm etc.

4.5 Enterprise Analytics

Enterprise Analytics refers to the practice of collecting and analyzing data from across an organization to gain insight and drive business planning and decision making. To accomplish this, Enterprise Analytics utilizes data from numerous sources, analyzes it for meaningful patterns and calculates business-defined Key Performance Indicators (KPIs). At Hydro One, Asset Management has implemented analytics to assess asset risk and support investment planning decisions. This project will implement the next generation high performance analytics, leveraging In-Memory technology. Analytic tools will include the existing SAP application as well as a new geo-spatial tool named Space, Time, Insight. The tools will be developed to consistently provide a comprehensive and cascading information view of asset risks based on demographics, condition, performance, criticality, economics and utilization.

4.6 Customer Experience Enhancements

This program will develop strategies which ensure Hydro One has agile business infrastructures that can adapt to fast-changing customer demand, and information systems that provide genuine insight into the nature of the customer experience being delivered. Initiatives will be implemented in improving customer facing interactions by communicating with our customers via non device dependent mobile applications; Enabling customers to create Mobile My Account; Transition customers to Self-Serve by enhancing My Account Functionality, Including Notifications and Alerts and promoting Self-Serve adoption and Optimize the Billing Experience through My Account Paperless Billing and Segment Billing Communications as well as help customers to determine where they can reduce their energy profile.

In order to strengthen our focus on improving the customer experience we will implement technologies that analyze our customer voice and text interactions with us. By building a rich, intuitive, intelligent customer experience and mining the data gleaned from these interactions for critical insights into trends, this will help transform Hydro One into a more customer-driven business.

4.7 Corporate Support Optimization

This project will replace a number of existing customized solutions (e.g. Incident Claims Management (ICM), Waste Management) that support the Health, Safety and Environment Line of Business – including management of incidents/claims/investigations/corrective actions, waste management and subsequent reporting, with a standard off-the-shelf SAP solution. It will also eliminate the need for interfaces with legacy systems. Similar to Cornerstone Phases 1 and 2, the scope consists of and is restricted to doing what is required to turn on the SAP product and make it work as designed in the business, with no SAP software customizations or unnecessary enhancements. This investment will be used to implement SAP EHSM module and configure appropriately to meet Hydro One's ICM requirements. This module in conjunction with the existing EAM sub-module will be used to manage and track our assets with toxic substances.

4.8 Mobile IT

Hydro One continues to leverage its investment in mobile software which is a standard enterprise mobile tool for data collection and work status reporting and will also interface with the GIS and SAP systems. The applications work in a connected (real time) or disconnected mode depending on the nature of the work being performed and the availability of telecommunications connectivity. In 2017, there is a lifecycle refresh project to keep the investment in the Enterprise Mobile platform vendor supported.

4.9 Engineering Design Transformation

The objective is to increase productivity and efficiency in the areas of engineering design. By transforming the methods and engineering design tools to modern and comprehensive solutions Hydro One can more effectively create the required engineering designs, using templates based on accepted standards with intelligent integration to reducing the effort to cascade changes across the many connected designs. We will achieve this by adopting best practices and leveraging and integrating best of breed in engineering design and content management applications. This increase in productivity will help in meeting our other strategic objectives and in particular, to achieving value for our customers and our shareholder. This investment will be used to replace software in the engineering disciplines such as Structural Design, Distribution Design and Standards Design Management. The enterprise content created from these tools will be taken and migrated into a single Engineering ECM, this Enterprise Content Management (ECM) will be integrated with Enterprise ECM.

4.10 Information Rights Management

The objective is to implement set of techniques, methods and technologies which protect sensitive Hydro One content and data such as financial data, intellectual property and communications from unauthorized access be it internal or external users to Hydro One. This project will also help address the fundamental problems associated with Data Loss. This technology will allow for information to be remote controlled. This means that information and its control can be separately created, viewed, edited & distributed. This investment will be used to implement a leading Information Rights Management solution which will allow us to stay compliant with internal and external security policies and to meet our commitments to NERC, CIP and Bill 198. In addition, this investment will enhance our Records Management program and ECM investments as it will allow Hydro One to control the dissemination and destruction of our records wherever they are being stored.

COMMON CORPORATE COSTS CAPITAL – FACILITIES AND REAL ESTATE AND STATION SECURITY INFRASTRUCTURE

1.0 INTRODUCTION

This exhibit addresses Facilities and Real Estate's ("F&RE") capital expenditures to acquire (own or lease) and maintain Hydro One office space and service centres and capital expenditures to enhance security infrastructure. Exhibit D1, Tab 3, Schedule 6 (Summary of Corporate Common Costs Capital) describes which RRFE outcomes are promoted by the investments set out in this Exhibit.

Table 1 presents total F&RE and security infrastructure capital expenditures for the Historic, Bridge and Test Years as well as the 2015-2019 Distribution amounts.

Table 1
Total Facilities and Real Estate and Security Infrastructure Capital Expenditures
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Major	35.2	29.3	23.5	16.3	42.7	42.4	38.5	38.5	43.7	43.9
MFA	0.8	0.5	1.2	1.2	5.5	5.5	1.5	1.5	1.5	1.5
Total	**36.0**	**29.8**	**24.7**	**17.5**	**48.2**	**47.9**	**40.0**	**40.0**	**45.2**	**45.4**

Description	Allocated to Distribution				
	2015	**2016**	**2017**	**2018**	**2019**
Major	16.5	14.6	14.7	17.0	17.0
MFA	2.5	0.7	0.7	0.7	0.7
Total	**19.0**	**15.3**	**15.4**	**17.7**	**17.7**

2.0 COMMON CORPORATE COSTS - FACILITIES & REAL ESTATE

Table 2 presents total F&RE capital expenditures for the Historic, Bridge and Test Years as well as the 2015-2019 Distribution amounts.

Table 2
Total Facilities and Real Estate Capital Expenditures
($ Millions)

Description	Historic				Bridge	Test				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Major	21.7	25.4	20.7	15.5	36.2	34.1	30.0	30.0	35.0	35.0
MFA	0.8	0.5	1.2	1.2	5.5	5.5	1.5	1.5	1.5	1.5
Total	**22.5**	**25.9**	**21.9**	**16.7**	**41.7**	**39.6**	**31.5**	**31.5**	**36.5**	**36.5**

Description	Allocated to Distribution				
	2015	**2016**	**2017**	**2018**	**2019**
Major	15.4	13.6	13.6	15.9	15.9
MFA	2.4	0.7	0.7	0.7	0.7
Total	**17.8**	**14.3**	**14.3**	**16.6**	**16.6**

The primary driver for the increase in costs is the need to provide suitable space and to accommodate the staff resources and equipment required to handle the substantial growth in core sustaining, development and operations work programs over this period (as described in Exhibits C and D). These expenditures encompass the refurbishment, acquisition and/or development of field facilities and the expansion and improvement of head office space.

2.1 F&RE Capital Expenditures

The F&RE major capital program allows for the provision of workspace for head office facilities, the Ontario Grid Control Centre in Barrie, and field administrative and service centre facilities.

Key Program work activities include:

- Addressing company accommodation requirements in terms of new buildings, buildings additions and major facility renovations;
- Replacement of major building components including roof structures, windows, heating, ventilating and air conditioning ("HVAC") systems and other structural elements and building systems;
- Dealing with environmental issues that may arise such as mould; and
- Water treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply.

a) Field Facilities Accommodations Requirements

Table 3
Total Field Facilities Capital Expenditures
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Major	21.3	25.1	15.9	10.2	25.0	25.0	30.0	30.0	35.0	35.0
MFA	0.8	0.5	0.8	0.0	1.5	1.5	1.5	1.5	1.5	1.5
Total	**22.1**	**25.6**	**16.7**	**10.2***	**26.5**	**26.5**	**31.5**	**31.5**	**36.5**	**36.5**

*An absence of suitable properties for new facilities hampered the execution of the 2013 field facilities capital program.

The capital work program includes improvements to existing facilities, building additions and new facilities in line with the company's operational requirements and responding to work program space demands. This program also focuses on ensuring critical facility structural and other building improvements to enhance the life of assets.

Maintaining building and site assets in a condition that ensures their long-term viability, while meeting the workspace needs of employees, on a day-to-day basis, is critical for the successful completion of a variety of corporate work activities. Hydro One contracts to have regular inspections of administrative and service centre sites across the province, ensuring critical building/site components (such as HVAC systems, roof, windows) are routinely inspected and major structural and related problems are identified. From the inspection recommendations, component replacement work is scheduled on a priority basis. Planned and corrective replacement of these critical components varies year over year based on recommendations from the facility service providers. The facilities infrastructure base is dominated by buildings and associated systems and components that are at or reaching the end of their asset life cycle. Approximately 40% of administrative and service centre facilities are estimated to be more than 40 years old. The aging facilities asset base in conjunction with work program demands and operational needs of the business units requires capital investment in order to continue to provide adequate workspace accommodation. These requirements will be addressed on a priority basis and/or as opportunities emerge. Further details are available in Exhibit D2, Table 2, Schedule 3.

b) Head Office and GTA Facilities Accommodation Requirements

Table 4
Total Head Office and GTA Facilities Capital Expenditures
($ Millions)

Description	**Historic**				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Major	0.4	0.3	4.8	5.3	11.2	9.1	0.0	0.0	0.0	0.0
MFA	0.0	0.0	0.4	1.2	4.0	4.0	0.0	0.0	0.0	0.0
Total	**0.4**	**0.3**	**5.2**	**6.5***	**15.2**	**13.1**	0.0	0.0	0.0	0.0

*The head office tenant improvement project is approximately 3 months behind schedule.

Capital investment of $15.2 million is required for bridge year 2014 and $13.1 million for test year 2015. This investment will provide for head office improvements.

In 2010, Hydro One secured an eleven-year lease for 483 Bay Street, to serve its ongoing head office requirements. Within the completed lease renewal of 483 Bay, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems/infrastructures and allowances for tenant improvements. The initially planned tenant improvements as outlined in the last distribution rate filling were ultimately deferred during years 2010 and 2011 given consideration to the capital reductions made by the Board in its last distribution decision and the economic situation in the Province of Ontario. The planned improvements are necessary now as major head office building infrastructure elements are now at the end of their life and require replacement. (This includes the raised flooring, which presents a health and safety issue with increasing number of tripping hazards.) Similarly, furniture systems acquired from the previous tenant and refurbished are also now considered to be at end of life.

In 2011 the company commenced renovations to head office space. The head office capital investment, consisting of both leasehold improvements and replacement furniture systems, are expected to continue throughout bridge year 2014 and test year 2015. The leasehold improvements and the furniture systems funding requirements are estimated to be in bridge year $15.2 million and in the following test year $13.1 million. The project costing reflects continuance of the open office environment, completion to standard commercial finishes and commitment to LEED certification. Further details are available in Exhibit D2, Table 2, Schedule 3.

c) Minor fixed Assets (“MFA”)

Office workstations and furniture are beyond the end of their normal service life and need to be replaced. Table 1 shows the estimated MFA expenditures in test years 2015-2019. This includes replacement of furniture and office equipment related to new and renovated space accommodation requirements.

3.0 SECURITY INFRASTRUCTURE

Table 5 summarizes the total security capital expenditure for the historic, bridge and 2015-2019 test years.

Table 5
Total Security Infrastructure Capital Expenditures
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Totals	13.5	3.9	2.8	0.8	6.5	8.3	8.5	8.5	8.7	8.9

Description	Allocated to Distribution				
	2015	2016	2017	2018	2019
Total	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**

Security infrastructure is designed to effectively deter, delay, detect and respond to security threats that target distribution and transmission stations. There are currently 1004 distribution stations. The Distribution Station Security Upgrade capital program follows a risk-based approach to address distribution stations based on their exposure to security threats. Distribution station security upgrades will be prioritized based on station criticality and the number of intrusion and theft occurrences. Copper in station ground grids, fence ground grids, ground connections and neutral connections for electrical equipment are often targeted for theft in Hydro One stations. The removal of ground and neutral copper connections compromises the electrical integrity of the grounding system. This can pose safety hazards to Hydro One employees, the general public and to the intruder. Thieves have gained access into stations by cutting through chain-link fence fabric or breaking lock mechanisms. This program will address distribution station security threats by providing reinforced fencing, providing barriers for ground grids and other security measures. This work will help to maintain reliability, reduce power outages and improve employee and public safety.

Security upgrade capital expenditures at distribution stations from 2015 to 2019 will range from $1.0 million to $1.1 million as per the table above. Approximately three stations are currently planned to be addressed per year. Based on the success of the security upgrades at deterring intrusions and theft, more distribution stations will be planned for security upgrades in future years. Further details are available in Exhibit D2, Table 2, Schedule 3.

COMMON CORPORATE COSTS CAPITAL - TRANSPORT, WORK AND SERVICE EQUIPMENT

1.0 INTRODUCTION

This exhibit identifies the Transport and Work Equipment ("TWE") and Service Equipment capital expenditures for the period 2010 to 2019. TWE and Service Equipment provides vehicle and specialized equipment support to the growing work programs across the organization. Exhibit D1, Tab 3, Schedule 6 (Summary of Corporate Common Costs Capital) describes which RRFE outcomes are promoted by the investments set out in this Exhibit.

2.0 TRANSPORT AND WORK EQUIPMENT

The decrease of $10.0 million in capital expenditures in 2015 from the bridge year 2014, as shown in Table 1, is related to the stabilization in work programs for the Electro-Forestry Journey Person Forestry Program (EFJP), Forestry and Provincial Lines Apprenticeship Programs, as well as the helicopter replacement schedule. As of December 31, 2013, Hydro One has approximately 7,300 TWE units with an original capital value ("OCV") of $516 million, of which approximately 650 units require replacement each year. Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers. Light vehicles are replaced after 6 years or 180,000 km, service trucks are replaced after 6 years or 300,000 km, and work equipment is replaced after 8 to 10 years or 400,000 km.

Table 1
Capital Expenditures From 2010 – 2019 ($ Millions)

Description	Historic				Bridge	Test					Allocated to Distribution				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	64.5	42.8	44.4	54.1	64.5	54.5	62.5	56.7	62.9	59.0	39.6	45.4	41.2	45.7	42.9

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process, to plan for future transportation requirements as well as identify the need to increase overall fleet size. The TWE Replacement Program annually analyzes 5-year cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital program, on an annual basis, is evaluated against the business plan and is subject to the work program prioritization and forecasting process.

Business cases for the program are prepared and approved and the equipment is strategically procured through a tendering process.

The TWE Replacement Program reviews:

- Equipment capital forecast;
- Equipment productivity, functionality, and future requirements;
- Equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- Safety/risk;
- Work programs, evaluating staff and equipment complement;
- Tendered procurement process;
- Fleet's Original Capital Value and Net Book Value;

- Historical and future utilization; and
- Strategic procurement.

The guidelines for vehicles considered for replacement are based on vehicles meeting predetermined criteria including, but not limited to: manufacturer's life expectancy, average cost per kilometer, regulated maintenance standards and safety/risk. Hydro One takes advantage of discounts by establishing purchasing cycles with manufacturers. As vehicles reach the targeted criteria, a vehicle maintenance evaluation is performed and, in some cases, the unit may be reassigned to other functions with "low usage" requirements. The replacement program measures the age and value of the fleet and meets the requirements and due diligence of a well managed Utility fleet.

The benefits of our replacement program include:

- Maximum safety, productivity and utilization;
- Maximizing equipment availability;
- Optimizing repair time, and fleet complement; and
- Maximizing efficiency and life cycle benefits

2.1 2010 to 2019 Period Analysis

As noted in Exhibit C1, Tab 4, Schedule 1 (Costing of Work), the overall size of Hydro One Networks Inc.'s fleet was adjusted to approximately 7,300 vehicles and other equipment in 2013 to match the work programs. TWE expenditures are forecasted to be $54.5 million in 2015 based on the number of vehicles required to execute the planned work programs and to support changing requirements of the EFJP and apprenticeship programs.

The increase in the capital requirement in 2013 over 2012 was directly related to the increase in the Provincial Lines and Forestry Apprenticeship Programs in anticipation of regular staff retirements and will be readjusted when the staff complement is right-sized. Of the $54.1 million spent in 2013, $4.5 million was required for Provincial Lines to accommodate the increase in work program to offset rental requirements and to support the Lines apprenticeship program, and $3.9 million was related to additional large equipment requirements for Forestry in order to facilitate changes in the apprenticeship program.

In 2014, the capital expenditure primarily reflects the amount required to maintain core Fleet requirements ($43.9 million). Of the total $64.5 million, $3.7 million is required to support the Forestry apprenticeship program and additional staffing, and $11.4 million is required to support the Provincial Lines increased pole-replacement program requirements, $0.9 million for 25 Forestry Chippers as part of a health and safety initiative, and $4.6 million for replacement of a helicopter.

In 2015, TWE capital expenditures of $54.5 million include the requirements for core TWE replacements ($45.2 million), incremental TWE requirements for Forestry EFJP staffing and Mechanical Brushing Program ($3.1 million), as well as the incremental TWE requirements for the increase in Provincial Lines Pole Replacement Program ($6.2 million).

In 2016, TWE capital expenditures of $62.5 million include the requirement for core TWE replacements ($48.2 million), incremental TWE requirements for Forestry EFJP staffing and Mechanical Brushing Program ($3.2 million), incremental TWE requirements for the increase in Provincial Lines Pole Replacement Program ($6.3 million), and replacement of a helicopter ($4.8 million).

In 2017, TWE capital expenditures of $56.7 million include the requirement for core TWE replacements ($51.4 million), incremental Fleet requirements for Forestry EFJP staffing and Mechanical Brushing Program ($2.1 million), as well as the incremental TWE requirements for the increase in Provincial Lines Pole Replacement Program ($3.2 million).

In 2018, TWE capital expenditures of $62.9 million include the requirement for core TWE replacements ($52.4 million), incremental TWE requirements for Forestry EFJP staffing and Mechanical Brushing Program ($2.2 million), incremental TWE requirements for the increase in Provincial Lines staff required for the Pole Replacement Program ($3.3 million), and replacement of a helicopter ($5.0 million).

In 2019, TWE capital expenditures of $59.0 million include the requirement for core TWE replacements ($53.5 million), incremental TWE requirements for Forestry EFJP staffing and Mechanical Brushing Program ($2.2 million), as well as the incremental TWE requirements for the increase in Provincial Lines Pole Replacement Program ($3.3 million).

As noted above, TWE capital expenditures include incremental requirements to replace single-engine helicopters with newer, safer, and more capable twin-engine helicopters in 2014, 2016 and 2018. This requirement is driven by regulatory changes being developed by Transport Canada. To protect public safety, Transport Canada has restricted low level single-engine flight in urbanized areas and has begun implementing more stringent waiver criteria limiting low level single-engine helicopter use in the future.

2.2 Capital vs. Operating Leases

The evaluation of leasing as a financial alternative to the approved capital program was evaluated during the 2003 strategic sourcing initiative. The evaluation included the review of both capital and operating leases and the total operating costs. The risks and benefits generated by leasing were evaluated and it was decided the risks outweighed the modest benefits. The results therefore indicated that leasing was not cost effective.

The requirement for short term rentals (as distinct from long term rentals) is recognized and is included with our operating expenses in Exhibit C1, Tab 4, Schedule 1.

2.3 Procurement Initiatives

In order to effectively manage costs over the next five years, Fleet Services follow capital procurement objectives for material and service acquisitions which include:

- Profile the commodities, collect and analyze cost drivers;
- Analyze the supply market;
- Develop a strategy for sourcing;
- Select the suppliers through a rigorous RFP process; and
- Conduct negotiations.

These procurement initiatives have allowed Hydro One to lock in pricing for three year terms with an option of renewal for a fourth and fifth year with preferred vendors.

3.0 SERVICE EQUIPMENT

Table 2 identifies the expenditures for Service Equipment for the 2010 to 2019 period.

Table 2
MFA Service Equipment 2010 – 2019 ($ Millions)

Description	Historic				Bridge	Test					Allocated to Distribution				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	3.8	6.7	9.8	8.1	9.8	9.1	7.9	7.9	7.0	7.0	4.2	3.6	3.6	3.2	3.2

Minor fixed assets for service equipment consists of capital items of $2,000 or more, required by Hydro One staff to carry out construction and maintenance work programs. Capital items less than $2,000 are expensed to OM&A. Minor fixed asset expenditures for service equipment are required to replace equipment at end of life, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with the work program.

Purchases in this category include specialized transportation equipment for off-road work sites and mobile equipment required to carry out a variety of work.

Specialized transportation equipment used for both Distribution and Transmission includes items such as all-terrain vehicles, boats, barges, snowmobiles and related accessories. Service Equipment also includes: mobile cranes, stringing equipment, Schnabel cars, and float trailers.

Mobile equipment includes oil tankers, de-gassifiers, and dry air machines required for transformer maintenance, SF6 gas carts required for the maintenance of SF6 breakers, and a variety of other equipment necessary to analyze, test, and carry out construction and maintenance associated with the work program.

Year-over-year changes in spending are largely the result of the evolving needs of distribution and transmission work programs. The $2.8 million (-29%) decrease in spending from 2014 to 2019 is largely due to Stations Services repairing or replacing fewer Oil Shipping Tankers, Mobile Degrassifiers and Railcar Movers. In addition, capital requirements related to Health, Safety and Environment decrease over the 2017 – 2018 period as investment in Automated External Defibrillators (AED), training and test equipment is lessened.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Utility Rate Base
Test Years (2015 to 2019)
Year Ending December 31
($ Millions)

Line No.	Particulars	2014	2015	2016	2017	2018	2019
	Electric Utility Plant						
1	Gross plant at cost	$ 9,865.4	$ 10,459.9	$ 11,021.6	11,676.8	$ 12,266.6	$ 12,786.8
2	Less: non-regulatory	(47.7)	(77.8)	(102.2)	(117.9)	(126.7)	(131.9)
3	Gross plant at cost for rate base	9,817.7	10,382.1	10,919.4	11,558.9	12,139.9	12,654.9
4	Less: accumulated depreciation	(3,686.3)	(3,927.1)	(4,180.9)	(4,466.7)	(4,712.7)	(4,919.1)
5	Less: non-regulatory	2.3	5.3	9.5	14.6	20.4	26.4
6	Accumulated depreciation for rate base	(3,683.9)	(3,921.8)	(4,171.4)	(4,452.0)	(4,692.3)	(4,892.6)
7	Net plant for rate base	6,133.7	6,460.3	6,748.0	7,106.8	7,447.6	7,762.3
8	Average net plant for rate base		6,297.0	6,604.1	6,927.4	7,277.2	7,604.9
9	Construction work in progress		0.0	0.0	0.0	0.0	0.0
10	Average net utility plant		$ 6,297.0	$ 6,604.1	$ 6,927.4	$ 7,277.2	$ 7,604.9
	Working Capital						
11	Cash working capital		249.9	253.6	257.3	257.2	257.7
12	Materials and Supplies Inventory		6.5	6.6	6.8	6.9	7.0
13	Total working capital		256.4	260.3	264.0	264.1	264.7
14	Total rate base		$ 6,553.3	$ 6,864.4	$ 7,191.4	$ 7,541.3	$ 7,869.6

COMPARISON OF NET CAPITAL EXPENDITURES – HISTORIC, BRIDGE YEAR AND TEST YEAR

Distribution Capital ($millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Sustaining Capital										
Stations	13.8	21.2	32.7	56.5	50.6	63.9	67.8	68.5	76.4	77.2
Lines	170.1	181.2	183.2	234.4	203.9	227.6	246.8	267.4	282.7	295.8
Meters	130.1	71.8	45.9	32.3	31.9	16.6	20.6	23.8	21.3	10.5
Total Sustaining Capital	**314.0**	**274.2**	**261.8**	**323.2**	**286.4**	**308.2**	**335.2**	**359.7**	**380.4**	**383.5**
Development Capital										
Connections, Upgrades	92.0	95.3	107.2	92.7	105.5	108.8	112.1	115.8	119.3	122.9
System Capability Reinforcement	49.3	45.9	56.7	70.0	61.1	81.4	71.5	83.2	62.0	74.2
Generation Connections	12.4	13.5	18.0	25.5	33.2	33.1	22.7	8.7	2.1	2.0
Wholesale Revenue Meters	9.3	2.4	4.0	3.9	0.4	0.0	0.0	0.0	0.0	0.0
Total Development Capital	**162.9**	**157.1**	**185.9**	**192.1**	**200.2**	**223.3**	**206.3**	**207.7**	**183.5**	**199.1**
Operations Capital										
Operations	1.2	1.3	2.7	3.6	5.1	9.4	18.8	7.0	7.0	4.2
Total Operations Capital	**1.2**	**1.3**	**2.7**	**3.6**	**5.1**	**9.4**	**18.8**	**7.0**	**7.0**	**4.2**

Distribution Capital ($millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer Service Capital										
Smart Grid Pilot	18.4	30.1	43.1	6.4	22.9	22.6	9.9	3.9	0.0	0.0
Total Customer Service Capital	**18.4**	**30.1**	**43.1**	**6.4**	**22.9**	**22.6**	**9.9**	**3.9**	**0.0**	**0.0**
Capital Common Corporate Costs and Other Costs										
Transport and Work, and Service Equipment	51.1	36.3	39.9	43.5	51.4	43.8	49.1	44.8	48.9	46.1
Information Technology	18.9	26.1	19.4	13.4	29.8	22.6	20.1	22.9	17.6	18.6
Cornerstone	8.3	49.6	67.8	47.6	8.7	0.0	0.0	0.0	0.0	0.0
Facilities & Real Estate	14.9	22.1	13.0	10.1	19.9	19.0	15.3	15.4	17.7	17.7
Other	0.0	-1.1	2.4	-2.9	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Common Corporate Costs and Other Costs	**93.2**	**133.0**	**142.5**	**111.7**	**109.9**	**85.4**	**84.5**	**83.1**	**84.2**	**82.3**
Total Distribution Capital	**589.7**	**595.7**	**636.0**	**637.0**	**624.5**	**648.9**	**654.7**	**661.4**	**655.1**	**669.1**

LIST OF CAPITAL EXPENDITURE PROGRAMS/PROJECTS IN EXCESS OF $1M

1.0 SUSTAINING CAPITAL (Exhibit D1, Tab 3, Schedule 2)

1.1 Stations

		2015	2016	2017	2018	2019
S1	Transformer Spares and Replacements	18.0	18.4	17.9	21.2	21.6
S2	Mobile Unit Substations	4.6	3.6	3.7	3.6	3.7
S3	Spill Containment	1.1	1.1	1.2	1.2	0.6
S4	Station Component Replacements	2.1	2.2	2.2	2.2	2.3
S5	Recloser Upgrades	1.4	1.4	1.4	1.5	1.5
S6	Demand Work	2.1	2.1	2.1	2.2	2.2
S7	Station Refurbishments	34.6	39.0	40.0	44.5	45.2

1.2 Lines

		2015	2016	2017	2018	2019
S8	Trouble Call and Storm Damage Response	58.2	60.8	61.6	62.0	62.5
S9	Joint Use and Line Relocations	26.7	27.3	27.8	28.4	28.9
S10	Pole Replacements	88.7	95.1	105.0	115.2	125.8
S11	PCB Lines Equipment Replacements	1.9	5.0	10.6	10.8	11.1
S12	Large Sustainment Initiatives	33.4	39.5	42.9	46.5	47.3
S13	Line Component Replacements	11.6	11.8	12.1	12.3	12.6
S14	Submarine Cable Replacements	7.1	7.2	7.4	7.5	7.7

1.3 Meters

		2015	2016	2017	2018	2019
S15	Meter Upgrades	10.0	15.8	18.8	16.1	5.0
S16	Meter Inventory Sustainment	4.6	4.8	5.0	5.2	5.5

Summary	2015	2016	2017	2018	2019
Total Sustaining projects/programs listed above	306.2	335.2	359.7	380.4	383.5
Sustaining projects/programs less than $1M	2.0	0.0	0.0	0.0	0.0
Total Sustaining Capital (per Exhibit D1-3-1)	**308.2**	**335.2**	**359.7**	**380.4**	**383.5**

2.0 DEVELOPMENT CAPITAL (Exhibit D1, Tab 3, Schedule 3)

2.1 Connections

		2015	2016	2017	2018	2019
D1	New Connections, Upgrades and Service Cancellations	108.9	112.1	115.8	119.3	122.9

2.2 System Capability Reinforcement

		2015	2016	2017	2018	2019
D2	Upgrades Driven by Load Growth	20.1	26.4	28.5	30.8	32.9
D3	Upgrades Driven by Load Growth - Distribution System Modifications	9.0	9.2	9.4	9.1	8.8
D4	Upgrades Driven by Load Growth - Demand Investments	3.6	3.7	3.8	3.4	3.4
D5	Asset Lifecycle Optimization and Operational Efficiency	8.1	9.7	8.9	4.2	4.5
D6	Reliability Improvements	2.7	2.0	2.6	1.6	2.2
D7	Orleans TS Capital Contribution	21.0	0.0	0.0	0.0	0.0
D8	Red Lake TS Capital Contribution	1.8	0.0	0.0	0.0	0.0

		2015	2016	2017	2018	2019
D9	Hanmer TS Capital Contribution	0.0	11.5	0.0	0.0	0.0
D10	Enfield TS Capital Contribution	0.0	0.0	0.0	0.0	11.1
D12	Leamington TS Capital Contribution	0.0	0.0	22.0	0.0	0.0

2.3 Distribution Generation Connection

		2015	2016	2017	2018	2019
D11	Recloser Retrofit Project	1.0	0.0	0.0	0.0	0.0

Summary	2015	2016	2017	2018	2019
Total Development projects/programs listed above	176.2	174.6	191.0	168.4	185.8
Development projects/programs less than $1M	47.1	31.7	16.7	15.1	13.3
Total Development Capital (per Exhibit D1-3-1)	**223.3**	**206.3**	**207.7**	**183.5**	**199.1**

3.0 OPERATIONS CAPITAL (Exhibit D1, Tab 3, Schedule 4)

		2015	2016	2017	2018	2019
O1	Operating Compute Refresh	0.0	0.0	0.0	0.9	1.9
O2	NOMS Refresh	0.0	1.4	0.0	0.0	0.0
O3	Operating Facilities Refresh	0.0	0.0	0.7	2.1	1.4
O4	BUCC – New Facilities Development	0.5	9.4	5.2	2.9	0.0
O5	OGCC Storage Area Network Upgrade	0.0	0.0	1.2	1.2	0.9
O6	ORMS Refresh	8.0	8.0	0.0	0.0	0.0

Summary	2015	2016	2017	2018	2019
Total Operations projects/programs listed above	8.5	18.8	7.0	7.0	4.2
Operations projects/programs less than $1M	0.9	0.0	0.0	0.0	0.0
Total Operations Capital (per Exhibit D1-3-1)	**9.4**	**18.8**	**7.0**	**7.0**	**4.2**

4.0 CUSTOMER SERVICE CAPITAL (Exhibit D1, Tab 3, Schedule 5)

Summary	2015	2016	2017	2018	2019
*Total Customer Service projects/programs***	22.4	8.0	1.5	0.0	0.0
Customer Service projects/programs less than $1M	0.2	1.9	2.4	0.0	0.0
Total Customer Service Capital (per Exhibit D1-3-1)	**22.6**	**9.9**	**3.9**	**0.0**	**0.0**

****detailed information regarding these projects may be found in Table 1, Exhibit D1,Ttab 3, Schedule 5.**

5.0 COMMON CORPORATE COSTS (Exhibit D1, Tab 3, Schedule 6)

5.1 Information Technology

		2015	2016	2017	2018	2019
IT1	Hardware/Software Refresh and Maintenance	12.0	11.2	10.1	10.1	10.1
IT2	MFA Servers and Storage	7.1	9.3	8.0	5.3	5.3
IT3	MFA PC and Printer Hardware	5.6	5.3	5.3	4.5	4.0
IT4	MFA Telecom Infrastructure	2.7	2.9	2.5	2.8	2.9
IT5	Field Workforce Optimization and Mobile IT	5.0	5.0	8.0	2.0	2.0
IT6	Customer Experience	5.0	1.0	4.0	1.0	3.0
IT7	Information Rights Management	0.0	0.0	0.0	2.5	2.5
IT8	Enterprise Analytics	2.0	2.0	2.0	0.0	0.0
IT9	Corporate Support Optimization	0.0	3.0	0.0	3.0	0.0
IT10	Engineering Design Transformation	0.0	0.0	0.0	4.0	3.0
IT11	Enterprise GIS	2.0	1.0	2.1	0.0	1.0

5.2 Common Corporate Costs and Other

		2015	2016	2017	2018	2019
C1	Real Estate Head Office and GTA Facilities Capital	13.1	0.0	0.0	0.0	0.0
C2	Real Estate Field Facilities Capital	26.5	31.5	31.5	36.5	36.5
C3	Transport and Work Equipment	54.5	62.5	56.7	62.9	59.0
C4	Service Equipment	9.1	7.9	7.9	7.0	7.0
C5	Security Infrastructure Capital	1.0	1.0	1.1	1.1	1.1

Summary	2015	2016	2017	2018	2019
Total Common Corporate Costs and Other projects/programs listed above	145.6	143.6	139.2	142.7	137.4
Common Corporate Costs and Other projects/programs less than $1M (includes Transmission Security Infrastructure)	9.2	9.5	9.4	9.6	9.8
Total Common Corporate Costs and Other capital (per Exhibit D1-3-1)	**154.8**	**153.1**	**148.6**	**152.3**	**147.2**

Costs Allocated to Distribution	2015	2016	2017	2018	2019
Total Common Corporate Costs and Other capital (per Exhibit D1-3-1)	**85.4**	**84.5**	**83.1**	**84.2**	**82.3**

INVESTMENT SUMMARY FOR PROGRAMS/PROJECTS IN EXCESS OF $1M

Sustaining Capital Programs ………………	Ref. S1 to S16
Development Capital Programs …………...	Ref. D1 to D12
Operations Capital Programs ……………...	Ref. O1 to O6
Common Corporate Costs and Other Capital ………..	Ref. IT1 to IT11
………..	Ref. C1 to C5

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Transformer Spares and Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the ageing demographic and deteriorating condition of the transformer assets through planned replacements and continued management of a strategic spare inventory to support the in-service distribution transformer population.

Need:
Transformers comprise the single largest component of Hydro One Distribution's station asset base. Hydro One Distribution owns and operates 1,214 distribution station transformers. As outlined in Exhibit D1, Tab 2, Schedule 1, the demographics of the distribution station transformer asset base is ageing and currently 19% of the transformers are beyond their expected service life. Over the next five years an additional 10% of the transformers will exceed the expected transformer service life. Transformers approaching their expected service life are prone to demonstrating signs of degradation including: leaks from failing/worn gaskets and fittings, deteriorating winding insulation, degrading insulating oil due to contaminants, or worn tapchanger parts. Approximately 24% of the distribution station transformers condition assessments fall into the high risk category. Other influencing factors are noise level requirements and environmental impact of leaking oil-filled transformers.

Transformer replacements under failure conditions are expensive, take a longer time to complete as compared to planned replacements and also place pressure on the mobile unit substation ("MUS") fleet resulting in the deferral of planned work.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Wait for transformers to fail while in service and replace them on a reactive basis with spare transformers, at a premium cost and with increased safety risks. Eventually the strategic spare inventory will become depleted, and with a limited number of MUS's to by-pass failed transformers there would come a point at which customers will sustain lengthy outages.

Alternative 2: "Status Quo"
Continue replacement of transformers at historical average rate of replacement. At this rate, the percentage of transformers beyond their expected service life will increase from 19% to 29% by the year 2020. This alternative is not sustainable; as the asset base continues to age the likelihood of failures will increase resulting in reduced customer reliability.

Alternative 3: "Increased Rate" (Recommended)
Replace transformers at a rate that balances the asset needs. At this rate, the percentage of transformers beyond their expected service life will be maintained.

Investment Description:
This program mitigates the risks associated with the transformer assets through planned replacement and the sustainment of spare inventory.

Transformer Replacements
The replacement of transformers is based on asset risk assessment which considers: equipment reaching the end of its expected service life, degrading condition, and deteriorating performance. Consideration is also given to transformers that produce noise which triggers customer complaints. The transformers planned for replacement over the five year period are outlined below.

Year	Transformer
2015	Brighton DS #2 - T1
	Fiddlers Green DS - T1
	Ottonabee DS - T1
	Rockland East DS - T1
	Vandeleur DS - T1
	Walkerton DS #2 – T1
2016	Clearwater Bay DS - T1
	Madawaska DS - T1
	Oil Springs DS - T1
	Owen Sound DS #2 - T1
	Rockland East DS - T2
	Wiarton RS - R2
2017	Anderdon DS - T1
	Blind River DS - T1
	Clarksburg DS - T1
	Colbourne DS #2 - T1
	Dresden DS - T1
	Wardsville DS - T1

Year	Transformer
2018	Belmont DS - T1
	Chatham Harwick DS - T1
	Duff DS - T1
	Rugby DS - T1
	Seaforth DS - T1
	Woodland Beach DS - T1
2019	Commanda DS - T1
	Drummond DS – T1
	Lebel DS - T1
	Millington DS - T1
	Whitedog DS - T2
	Young Jct RS - R1

These planned transformer replacements are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

Transformer Spares

Strategic spare transformers are required to be used as replacements for failed units or to aid in the avoidance of a major failure. The yearly candidates of strategic spares purchased are dependent on which categories of spare transformers are deployed each year under failing and failed conditions. The number of major transformer failures combined with the number of major failures avoided is on average 15 per year. Taking into consideration the failure rate along with the ageing and degrading condition of the in-service transformer population, the number of strategic spares required over the test years are outlined in the table below.

Year	2015	2016	2017	2018	2019
Number of Spare Purchases	26	27	26	31	32

Result:

The transformer spares and replacement program will result in:

- Addressing the ageing demographic issues,
- Reducing the risk of lengthy equipment outages, and
- Maintaining customer supply reliability.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	18.0	18.4	17.9	21.2	21.6	97.0
Operations, Maintenance & Administration and Removals (B)	0.1	0.1	0.1	0.1	0.1	0.5
Gross Investment Cost (A+B)	18.1	18.5	18.0	21.3	21.7	97.5
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	18.0	18.4	17.9	21.2	21.6	97.0

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve customer interruption time by maintaining an adequate level of spare transformers.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading transformers.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators through sustaining an adequate level of spare transformers to minimize interruption time and by replacing ageing and degrading transformers prior to failure event.
Financial Performance	• Cost savings are recognized when transformers are replaced proactively rather than reactively; as failed transformers take longer to replace making it more costly.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Mobile Unit Substations Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the Mobile Unit Substation ("MUS") fleet through planned refurbishments and acquisitions of MUS's to ensure an adequate, safe and reliable fleet of MUSs is available to satisfy outage needs during emergency failures, planned maintenance and capital projects.

Need:
Hydro One Distribution presently owns a fleet of 28 MUS's that are strategically located across the province. The MUS fleet is required to be in safe and reliable condition to support emergency failures, maintenance and capital projects.

The two major components of the MUS are the transformer and trailer. As outlined in Exhibit D1, Tab 2, Schedule 1, currently 61% of the MUS transformers and 39% of the MUS trailers are beyond their expected service life. Assets at their expected service life are prone to demonstrating signs of degradation. Also some of the MUS transformers have limited capacity or lack voltage regulation capability; which limits the utilization of the MUS. To address the deteriorating condition and demographics of the MUS fleet, replacement of the MUS transformers and trailers is required.

Furthermore, with the escalation of work programs to address ageing infrastructure on the distribution system, there has been additional strain placed on the MUS fleet to ensure customer outages are minimized. As such, there is a need to increase the present fleet of 28 MUS's to ensure there is an adequate number and type of MUS's. An inadequate MUS fleet would have an adverse impact on emergency failure response that would jeopardize customer reliability and would negatively impact the ability of Hydro One Distribution to proceed with maintenance and capital work programs.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Continue to utilize the existing MUS fleet in its existing condition. This would result in limiting the capability of the MUSs to support the work programs thus negatively impacting the reliability of the distribution system and increasing the risk of longer customer outages.

Alternative 2 “Replace Assets” (Recommended)
Address the end of life component issues on the existing MUS fleet and expand the fleet through procuring new MUSs. This would ensure an adequate MUS fleet in a state of readiness to address the customer supply requirements when failures occur or planned projects are executed.

Investment Description:
This program addresses the refurbishment and renewal of the MUS fleet. A s transportable mobile units, MUS’s must adhere to the requirements of the Highway Traffic Act. The MUS’s are required to be inspected. The inspections track the condition of the fleet which assists in the prioritization of refurbishments. MUS’s are identified under the refurbishment program when components of the MUSs have reached their expected service life and where condition is failing. MUS refurbishments planned over the five year period target the replacement of the MUS trailers and MUS transformers as outlined below.

Year	Trailer Replacements	Transformer Replacements
2015	MUS 28	
	MUS 34	
2016	MUS 24	
	MUS 26	
	MUS 37	
2017	MUS 33	
2018	MUS 08	
	MUS 35	
2019		MUS 04
		MUS 07
		MUS 17
		MUS 21
		MUS 29

The replacement trailers will include new trailers with air ride suspensions and hydraulically operated landing gear to address safety concerns with old manually operated landing gear. It will also address installing super structures for the high and low voltage equipment, upgrading from fused feeders to reclosers, installing new high and low voltage switches as well as buswork, insulators and lightning arresters. Trailers will meet all Ministry of Transportation requirements with additional safety and “ease of operation” features incorporated into the design.

The replacement transformers will include higher capacity ratings in some categories to meet the higher loading demands at stations. T he transformers will be procured to the following specifications.

	MUS 29:	MUS 07 and 17:	MUS 04 and 21:
Primary Voltage:	115 kV	44 kV	27.6 kV
Secondary Voltages:	27.6/25/13.8/12.47/8.32 kV	12.47/8.32/4.16 kV	8.32/4.16kV
Voltage Regulation:	High Voltage ULTC	Low Voltage ULTC	Low Voltage ULTC
Capacity:	15 MVA	7.5 MVA	7.5 MVA

In addition to MUS refurbishments, new MUS's are also required to support both the emergency failures and increasing planned maintenance and capital work programs. The MUS purchase plans over the five year period are outlined below:

Year	2015	2016	2017	2018	2019
Number of MUS Purchases	1	1	1	1	0

The four new MUSs (two 27.6 kV and two 44 kV) will be procured to the following specifications:

	27.6kV MUS:	44kV MUS:
Primary Voltage:	27.6 kV	44kV
Secondary Voltages:	8.32/4.16 kV	13.8/8.32/4.16 kV
Voltage Regulation:	Low Voltage ULTC	Low voltage ULTC
Capacity:	7.5 MVA	7.5 MVA

These new MUSs will ensure there is an adequate number and type of MUSs available to support the initiatives required to maintain and upgrade the distribution system.

Result:

The mobile unit substation program will result in:

- Ensuring an adequate MUS fleet to support failures and other planned work without unacceptable outage impacts to customers,
- Ensuring the MUS fleet remains in good repair and does not present any safety hazards, and
- Maintaining the reliability of the distribution system.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	4.6	3.6	3.7	3.6	3.7	19.2
Operations, Maintenance & Administration and Removals (B)	0.3	0.3	0.3	0.3	0.3	1.5
Gross Investment Cost (A+B)	4.9	3.9	4.0	3.9	4.0	20.7
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	4.6	3.6	3.7	3.6	3.7	19.2

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve customer interruption time by maintaining the condition and ensuring an adequate level of mobile unit substations to respond to failure events.
Operational Effectiveness	• Maintain customer supply reliability by maintaining the condition and ensuring an adequate level of mobile unit substations to carry the station load while performing capital and maintenance work to mitigate power disruption to customers.
Public Policy Responsiveness	• Comply with Ministry of Transportation licensing requirements by ensuring the units are roadworthy and electrically functional.
Financial Performance	• Utilization of mobile unit substations provides a cost effective alternative to constructing redundant transformation at stations across the province.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Spill Containment
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To minimize the risks to the environment, in the event of a transformer failure releasing insulating oil beyond the station, through the installation of a spill containment system.

Need:
Hydro One Distribution owns and operates 1004 distribution stations across the province. Only about 80 of these distribution stations are equipped with a spill containment system. Some of the distribution stations are located near: bodies of water, Provincial Significant Wetlands, First Nation reserves, potable wells or other sensitive receptors that could be impacted by the release of oil resulting from a failure of a distribution station transformer.

Hydro One Distribution assesses the spill risk of all its station locations. Assessments determine site specific plans to reduce the risk of releases of insulating oil to the environment at sites deemed high risk, either by the installation of spill containments or other means of risk reduction such as:

- the installation of new non PCB transformers with sealed tank designs which reduce the risk of oil releases should a failure occur,
- the installation of upgraded lightning protection to improve protection of the transformer during storms, or
- the replacement of explosion vents with a pressure relief device reducing the risk of releasing large volumes of oil.

Hydro One Distribution has identified approximately 25 stations as high risk. Hydro One Distribution must exercise a due diligence approach regarding distribution stations site spill management adhering to the Ministry of Environment, *Environmental Protection Act* and the Hydro One Environmental Policy.

Alternatives:

<u>Alternative 1: "Do Nothing"</u>

Continue to operate the distribution stations without spill containment systems at all high risk locations. Transformer failure at these high risk distribution stations could result in harmful impacts to the environment with lasting effects.

<u>Alternative 2: "Install Systems" (Recommended)</u>

Install spill containment systems to address distribution stations with high risk of impact to the environment. The impact of the oil release will be greatly reduced as the oil will be contained within the spill containment before it reaches the surrounding receptors.

Investment Description:

Distribution stations are identified for installation of spill containment based on the stations that present the highest risk to the environment. A spill containment system (as depicted in the picture below) captures and controls transformer oil spills and leaks, minimizing the risk of environmental impacts. The Ministry of Environment issues certificates of approval for these engineered spill containments.

Ten spill containment systems are planned for installation over the five year period. These spill containment installations will reduce the risk of transformer oil releases into sensitive receptors near the site. The stations targeted for spill containment are outlined below.

Year	Station
2015	Halls Lake DS
	Rockwood DS
2016	Bala River DS
	Minaki DS
2017	Little Britain DS
	Nobleton DS
2018	Napanee Mills DS
	Vittoria DS
2019	Reach Road RS
	Fenelon Falls Clifton DS

These spill containment installations are limited to cases were no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the spill containment work is bundled into an integrated Station Refurbishment project as outlined in Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

Result:

The installation of spill containment will result in:

- Reducing environmental impact of oil release resulting from transformer failures, and
- Ensuring compliance with Ministry of Environment's *Environmental Protection Act* and Hydro One's Environmental Policy.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	1.1	1.1	1.2	1.2	0.6	5.2
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	1.1	1.1	1.2	1.2	0.6	5.2
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	1.1	1.1	1.2	1.2	0.6	5.2

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Mitigate health and safety hazards to customers and the public by minimizing the risk of transformer oil releases into sensitive receptors near the distribution station.
Operational Effectiveness	• Ensure continuous improvement of distribution stations by installing spill containment system to reduce environmental impacts resulting from the release of transformer oil.
Public Policy Responsiveness	• Adhere to the Ministry of Environment's Environmental Protection Act when proactively managing transformer spill containment system infrastructure.
Financial Performance	• Cost savings are recognized in the event of transformer failure, as the spill containment system mitigates oil release into the environment that would otherwise have a potential for costly clean-up.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Component Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the existing distribution station assets through planned replacement of components that have deficiencies, safety issues, design shortfalls, manufacturer defects or have reached the end of their expected service life.

Need:
Hydro One Distribution owns and operates 1004 distribution stations across the province. Inspections and preventative maintenance programs are used to assess the condition of the assets at distribution stations. As outlined in Exhibit D1, Tab 2, Schedule 1 there is a trend of ageing demographics for distribution station assets. Equipment approaching its expected service life is prone to demonstrating signs of degradation. Other influencing factors that affect the reliable operation of the distribution system include components that have safety issues, design shortfalls, or manufacturer defects. The distribution station assets, which includes switches, fuses, insulators, support structures, station service and fences must be replaced or refurbished to mitigate their associated risks.

Alternatives:
<u>Alternative 1: “Do Nothing”</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative 2: “Replace Assets” (Recommended)</u>
Proactively replace distribution station components that have deficiencies, safety issues, design shortfalls, manufacturer defects or have reached the end of their expected service life. This alternative will maintain the safety and reliability of the distribution stations.

Investment Description:
This program addresses the individual replacement of distribution station components. The components are identified annually for replacement based on the condition of the asset. These replacements are coordinated with maintenance activities, where possible, to reduce the number of outages. Replacements under this program include but are not limited to the following:

Fences
Station fences identified in deteriorated condition or of substandard height require replacement to maintain public safety and security.

Switches
Switches are prone to failure due to seized bearings or load interrupters, and failure of porcelain insulators. Replacement is required to ensure the reliability and operability of the system.

Fuses
Switch/fuse assembly fuses and "recloser by-pass" fuses are prone to falling due to hairline cracks in porcelain support insulators. Replacement is required to mitigate the safety risks of falling equipment.

Structures
Mobile unit substation poles and "dead-end" poles identified as beyond their expected service life and in deteriorated condition require replacement to ensure the reliability of the system.

Station Service
Batteries and chargers identified as beyond their expected service life or in deteriorated condition require replacement to ensure the operation of protection and control devices, breakers, and circuit switchers in the event of a loss of station service power supply.

On average a total of 30 components will require replacement annually over the five year period. These planned component replacements are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

Result:
The station component replacements program will result in:
- Addressing the ageing demographic issues,
- Mitigating the risk of safety concerns with failed or defective assets,
- Improving the reliability of the distribution system, and
- Reducing the risk of lengthy equipment outages affecting customers.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	2.1	2.2	2.2	2.2	2.3	11.0
Operations, Maintenance & Administration and Removals (B)	0.2	0.2	0.2	0.2	0.2	0.8
Gross Investment Cost (A+B)	2.3	2.3	2.4	2.4	2.5	11.8
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	2.1	2.2	2.2	2.2	2.3	11.0

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing distribution station components prior to failure.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading distribution station components.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by replacing ageing and degrading distribution station components prior to failure. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a station inspection.
Financial Performance	• Cost savings are recognized when distribution station components are replaced proactively rather than reactively; as failed components take longer to replace making it more costly.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Recloser Upgrades
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the ageing demographics and technical obsolescence of the recloser population through planned replacements in order to maintain customer reliability and performance.

Need:
Hydro One's distribution system has approximately 2,174 three phase equivalent station reclosers. Older reclosers have become technically obsolete and are no longer supported by the manufacturer. Frequent maintenance is required for these reclosers in order to maintain their operability which results in load transfers and interruption in load supply. Also, these older reclosers have demonstrated a higher risk of failure than the newer vacuum technology reclosers.

There are also concerns that some of the existing reclosers no longer have sufficient short circuit capability due to system reconfiguration. Station short circuit ratings can increase due to load growth, the addition of generation on feeders, and the installation of higher rated station transformers.

In other cases, the distribution station may have no reclose capabilities as fuses are used as feeder protection. This results in reduced reliability and performance for customers.

Alternatives:
<u>Alternative #1: "Do Nothing"</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative #2: "Replace Assets" (Recommended)</u>
Proactively replace reclosers that have reached the end of their expected service life. This alternative will maintain the safety and reliability of the distribution stations. Future maintenance cost will be reduced as vacuum technology requires far less maintenance.

Investment Description:
This program focuses on the replacement of oil filled reclosers that have reached the end of their expected service life and are defective or technically obsolete as a result of being discontinued by the manufacturer. It also includes installing reclosers on feeders that currently use fuses to provide feeder protection; as well as upgrading reclosers that have insufficient short circuit rating. Based on the asset risk assessment of the recloser population the following 85 feeders have been identified for recloser upgrades.

Year	Feeders
2015	Anderdon DS (F1, F2)
	Brighton Sharpe DS (F1, F2, F3)
	Butternut DS (F1, F2)
	Harrowsmith DS (F2, F3, F4, F5)
	Marionville DS (F2)
	Newington DS (F1, F2)
	Pinestone DS (F1, F2, F3)
2016	Alex East Boundary DS (F1, F2, F3)
	Coldwater DS (F1, F2, F3)
	Reddendale DS (F1, F2, F3)
	Rockland East DS (F2, F3, F4, F5, F6)
	Russell DS # 2 (F1, F2, F3)
	Stirling Baker DS (F1, F2)
	Warren DS (F1, F2, F3)
2017	Calstock DS (F1, F2)
	Exeter Rosemount DS (F1, F2, F3)
	Longueuil DS (F2, F3, F4)
	Manitouwadge DS # 2 (F4, F2)
	Oustic DS (F1, F2, F3)
	Puslinch DS (F1, F2, F4)
	Wesley DS (F3, F4)
2018	Alex West Boundary DS (F1, F2)
	Belleville DS #2 (F1, F2)
	Moosonee DS (F1, F2)
	Sowerby DS (F1, F2)
	Wendover DS (F1, F2, F3)
	Wharncliffe DS (F1)
	White River DS (F1, F2, F3)
2019	Brighton Pinnacle DS (F1, F2, F3)
	Chapleau DS (F3, F4)
	Constance DS (F1, F2, F4)
	Trenton Pelham DS (F1, F2, F3, F4)

The reclosers will be replaced with new reclosers that utilize vacuum technology. This new generation of reclosers also provides remote control and monitoring features consistent with smart grid requirements, reduced maintenance cycles and more flexibility and accuracy with settings. The new vacuum reclosers that are being installed reduce costs associated with fuse coordination by providing more replacement flexibility due to their higher fault current ratings and structure adaptability. Recloser settings can be changed without the need for intrusive upgrades to the recloser.

These planned recloser upgrades are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

Result:

Recloser upgrades will result in:

- Addressing the ageing demographic issues,
- Reducing customer outages,
- Minimizing future maintenance cost, and
- Providing the ability for remote communication.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	1.4	1.4	1.4	1.5	1.5	7.2
Operations, Maintenance & Administration and Removals (B)	0.1	0.1	0.1	0.1	0.1	0.4
Gross Investment Cost (A+B)	1.5	1.5	1.5	1.6	1.6	7.6
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	1.4	1.4	1.4	1.5	1.5	7.2

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers by proactively upgrading reclosers prior to failure.
Operational Effectiveness	• Maintain customer supply reliability by upgrading ageing and degrading reclosers.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading reclosers prior to failure.
Financial Performance	• Cost savings are recognized when reclosers are upgraded with new reclosers that utilize vacuum technology that have reduced maintenance cycles.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Demand Work Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Customer Focus

Objective:
To respond to service interruptions or other system deficiencies in order to maintain the safe operation and acceptable performance of distribution stations in compliance with the Distribution System Code.

Need:
A number of situations may arise that require immediate response by Hydro One Distribution personnel. Extreme weather or asset failure may result in a service interruption that requires restoration of power to maintain reliability. Regular inspections may identify damaged or failed distribution station assets that pose a safety hazard or customers may report power quality issues. During any such events, Hydro One Distribution is obligated to provide this service in accordance with good utility practice and the requirements of the Distribution System Code.

Alternatives:
No alternatives are considered, since failure to quickly respond to service interruptions or other situations where assets have failed would violate the Distribution System Code and result in unacceptable reliability and safety risks.

Investment Description:
This program addresses the replacement or repair of failed or failing distribution station equipment in a timely manner in order to secure reliability or safety. Examples of the most common work that is undertaken under the demand work program are as follows:

- Replacement or repair of failed power transformers
- Replacement or repair of reclosers, insulators or switches

These failures are difficult to predict, but must be addressed quickly because they generally result in customer interruptions or present significant safety risks. Planned expenditures are projected based on historical trends and adjusted to reflect recent experience.

Result:

The demand work program will result in:

- Responding to outages in an expedient manner,
- Addressing immediate reliability and safety risks, and
- Complying with regulatory requirements.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	2.1	2.1	2.1	2.2	2.2	10.7
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	2.1	2.1	2.1	2.2	2.2	10.7
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	2.1	2.1	2.1	2.2	2.2	10.7

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

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Minimize customer interruption duration by carrying out demand work in a timely manner.
Operational Effectiveness	• Maintain the safe operation and acceptable performance of distribution stations by addressing immediate reliability and safety risks.
Public Policy Responsiveness	• Comply with the Distribution System Code and Distribution Rate Handbook by maintaining the service quality indicators.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Refurbishments
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To refurbish an entire distribution station or part of a distribution station to address assets approaching the end of their expected service life that have a high risk of failure.

Need:
As outlined in Exhibit D1, Tab 2, Schedule 1, distribution station assets are ageing and a number of components are near the end of their expected service life. There are also concerns with the condition of the distribution station assets, including rotting high and low voltage wood structures, failing tube and clamp structures, deteriorated transformers, obsolete or faulty station equipment, fence and grounding systems.

Many assets reaching the end of their projected service life also coincide with poor reliability performance. Station failures could occur with lengthy customer outages realized.

Some other factors contributing to the need for the refurbishment of a station are: loading requirements, lack of mobile unit substation connection facilities, obsolete equipment, customer issues, operational problems, environmental spill risk mitigation, and safety issues or a combination of all of these factors.

Alternatives:
<u>Alternative 1: “Do Nothing”</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative 2: “Individual Component Replacements”</u>
Replace individual defective assets in distribution stations on a component basis. While this type of replacement is performed in some cases, it is not ideal. Individual component replacements do not allow efficiencies associated with the integrated replacement of a number of components at once.

Alternative 3: "Station Refurbishment" (Recommended)
Refurbish entire stations or parts of a station to current Hydro One Distribution standards in order to improve the reliability of the distribution system. The refurbishment of the station will result in reduced costs and will extend the life of the station.

Investment Description:
Distribution station assets deteriorate over time and should be replaced as they reach their expected end of service life. Stations are identified and prioritized for refurbishment based on asset risk assessments. Through station refurbishment a higher reliability is obtained by the installation of new equipment and other infrastructure.

The refurbishment will address: aged transformers and structures, defective equipment, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues. The stations will be refurbished to comply with present standards. Noise assessments are completed for station refurbishments that require the replacement of the transformer. If the noise of the transformer is an issue; a new transformer with lower noise levels will be installed. Landscaping, low profile designs, and wood fences are also incorporated into the station design where sites are located in urban areas.

Each station refurbishment will vary in size and scope. The average capital investment for each station refurbishment is below $1 million. The station refurbishments planned over the five year period are outlined below.

Year	Stations		
2015	Abbey DS	Dorchester DS	Perrault Falls DS
	Alexander Kenyon West DS	Exeter DS#2	Plattsville DS
	Berwick DS	Forest Jefferson DS	Princeton DS
	Blenheim DS	Geraldton South DS	Russell DS
	Bolsover DS	Haliburton DS	St. Thomas DS
	Brigden DS	Kemptville Van Buren DS	Stouffville 10th Line DS
	Brockville Park DS	Kingsville Pulford DS	Tara DS
	Brockville Water DS	Kirkland Lake Goodfish	Tralee DS
	Carleton Place	Lindsay Eglinton DS	Trenton McAuley DS
	Chatham Raleigh DS	Little Current DS	Wainfleet DS
	Corbeil DS	Marathon DS	Warkworth DS
	Deep River DS	Merlin DS	Wyoming Churchill DS

Year	Stations		
2016	Adams Point DS	Fenelon Falls Elliot DS	Newport DS
	Bismark DS	Gorrie DS	Nipigon DS
	Bobcaygeon Ann DS	Gravenhurst DS	Pointe Au Baril DS
	Carp DS	Guthrie DS	Port Lambton DS
	Consecon DS	Holland Landing DS	Precious Corners DS
	Craigleith DS	Horsey Bay DS	Shannonville DS
	Crozier DS	Kirkland Lake DS #1	Sutton Base Line #1 DS
	Devlin DS	Longlac East DS	Thorold Turner DS
	Dover Centre DS	McGregor DS	Vanastra DS
	Dundas Sydenham DS	Meaford Louisa DS	Wallaceburg DS
	Elk Lake DS	Meaford Thompson DS	Waupoos DS
	Elliot Lake DS	Mountain Chute DS	Wingham DS
	Elora Union DS	New Liskard Halibton DS	
2017	Arnprior Airport DS	Deseronto DS	Perth DS
	Arnprior Elgin DS	Drumbo DS	Perth North DS
	Arnprior McLachlin DS	Firth Corners DS	Pinelands DS
	Aspdin DS	Galetta DS	Rockland DS
	Athens DS	Hawley DS	Smithfield DS
	Black Corners DS	Kemptville West DS	Sturgeon Falls DS
	Brockville Cedar DS	Killaloe DS	Thamesville North DS
	Brockville Schofield DS	Manitouwadge DS #1	Trenton McNichol DS
	Cameron DS	Marthaville DS	Wartburg DS
	Clarence DS	Meaford Vincent DS	Welcome DS
	Collins Bay DS	Milford DS	Whitney DS
	Corunna DS	Monkton DS	Yarmouth Centre DS
	Cumberland DS	Owen Sound 12 St E DS	
2018	Alexander DS	Forest Jura DS	Owen Sound 2 Ave E DS
	Battersea DS	Glengarry DS	Pleasant Point DS
	Beaumaris DS	Haycroft DS	Red Rock DS
	Bolton Hardwick DS	Horningmill DS	Ridgetown Palmer DS
	Cedar Mills DS	Jones Road DS	Ripley DS
	Clayton DS	Joyceville DS	Rock Mills DS
	Creemore DS	Kennisis Lake DS	Roseville DS
	Dack DS	Kleinburg DS	Rylston DS
	Deleware DS	Lagoon City DS	Sam Lake DS
	DorcasBay DS	Madoc Madawaska DS	Shedden DS
	Dunchurch DS	McCrimmon DS	Shelburne Andrew DS
	Erin DS	Merrikville DS	Snelgrove DS
	Fenelon Falls DS	Mindemoya DS	Wiarton Claude DS
	Flynn Corners DS	Owen Sound 12 St W DS	

Year	Stations		
2019	Aberfoyle DS	Golden Valley DS	Punkidoodles Corners DS
	Addison DS	Huntsville DS	Ruthven DS
	Alexandria Margaret DS	Kerwood DS	Sharon DS
	Blythswood DS	Keswick DS	Sleeman DS
	Bondhead DS	Lanark DS	Smith Falls DS
	Buckhorn DS	North Brook DS	Taylor Kidd DS
	Carleton Place Francis DS	Omemee DS	Thedford DS
	Chatham Raleigh RS	Osgood DS	Vankleek Terry Fox DS
	Chesterville Bran DS	Ospringe DS	Vienna DS
	Cobalt DS	Oxford Mill DS	Virginiatown DS
	Dunedin DS	Park Road DS	Wanup DS
	Emo DS	Picton Barker DS	Wellington Wharf DS
	Farlain Lake DS	Pinegrove DS	Wooler DS
	Fonthill RS	Prospect DS	

Result:
Station refurbishments will result in:

- Addressing the ageing and degrading condition of distribution stations in a cost-effective manner,
- Ensuring the safe and reliable operation of the distribution system, and
- Reducing the risk of lengthy equipment outages caused by equipment failure or malfunction.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	34.6	39.0	40.0	44.5	45.2	203.3
Operations, Maintenance & Administration and Removals (B)	2.4	2.6	2.7	2.9	3.0	13.6
Gross Investment Cost (A+B)	37.0	41.6	42.7	47.4	48.2	216.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	34.6	39.0	40.0	44.5	45.2	203.3

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of planned outages at distribution stations that impact customer supply with the integrated approach to station refurbishments.
Operational Effectiveness	• Maintain safe operation and reliability of the distribution station by addressing all ageing and degrading equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading equipment prior to failure.
Financial Performance	• Cost savings are recognized when all ageing and degrading components within the station are replaced as part of the same project.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Trouble Call and Storm Damage Response Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Customer Focus

Objective:
To respond to service interruptions or other system deficiencies in compliance with the Distribution System Code.

Need:
A number of situations may arise that require immediate response by Hydro One Distribution personnel. Extreme weather or asset failures may result in a service interruption. Regular patrols and inspections may identify damaged or failed distribution assets that pose a safety hazard. Customers may report power quality issues. During any such events, Hydro One Distribution field crews must be dispatched to assess and resolve any urgent deficiency.

Alternatives:
No alternatives are considered, since failure to quickly respond to service interruptions or other situations where assets have failed would violate the Distribution System Code and result in unacceptable reliability and safety risks.

Investment Description:
Hydro One's distribution system services about 1.2 million customers that place a high value on both reliability and quality of power. This demand program encompasses the capital costs associated with responding to trouble calls, storm damage, power interruptions and other situations that pose reliability or safety risks and require immediate attention. Planned expenditures for this demand program are projected from historical costs and anticipated needs.

The trouble call and storm damage response program includes the following activities:

- Emergency pole and equipment replacements;
- Emergency submarine and underground cable replacements;
- Storm damage response, resolving service interruptions caused by adverse weather conditions;
- Post trouble response, providing permanent solutions to any temporary repairs that were required during an emergency or a service interruption;

- Power quality response, resolving unacceptable voltage or frequency levels; and
- Damage claims, including payment for third party damage that Hydro One Distribution cannot recover.

Trouble call response affects the company's performance on a number of OEB-specified service quality requirements; specifically, SAIDI and CAIDI reliability indices.

Results

The trouble call and storm damage program will result in:

- Ensuring Hydro One Distribution's ability to respond to trouble calls, service interruptions, and power quality complaints,
- Mitigating reliability and safety risks, and
- Complying with regulatory requirements.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	60.3	63.0	63.9	64.3	64.8	316.3
Operations, Maintenance & Administration and Removals (B)	8.2	8.6	8.7	8.8	8.8	43.1
Gross Investment Cost (A+B)	68.5	71.6	72.6	73.1	73.6	359.4
Recoverable (C)	(2.1)	(2.2)	(2.3)	(2.3)	(2.3)	(11.2)
Net Investment Cost (A+C)	58.2	60.8	61.6	62.0	62.5	305.1

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

Note: *The costs for forestry and premium time incurred as part of storm damage restoration are captured as part of OM&A Trouble Calls.*

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	90%	10%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Minimize customer interruption duration by carrying out demand work in a timely manner. Respond to customer complaints related to power quality or potential safety hazards.
Operational Effectiveness	• Maintain the safe operation and acceptable performance of the distribution system by addressing immediate reliability and safety risks.
Public Policy Responsiveness	• Comply with the Distribution System Code and Distribution Rate Handbook by maintaining the service quality indicators.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Joint Use and Line Relocations Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To provide line upgrades or relocations in compliance with legal agreements and applicable statutes.

Need:
Hydro One Distribution must meet contractual obligations to joint use partners as per existing Joint Use Agreements. In addition, a growing number of distributed generators have become third parties on poles owned by Hydro One Distribution, causing an increase in the number of upgrades required to Hydro One Distribution assets.

Hydro One Distribution is also obligated to perform line relocation work at the request of Municipal and Provincial road authorities as per the requirements of the *Public Service Work on Highways Act* and associated Ministry of Transportation guidelines, as well as line relocation work requested by customers in accordance with Hydro One Distribution's Conditions of Service.

Alternatives:
No alternatives are considered, since failure to perform the requested work would place Hydro One Distribution in violation of contractual obligations.

Investment Description:
This program addresses the externally driven requirements for joint use work and line relocations. Due to the nature of this work, the number of projects can vary from year to year. Planned expenditures are projected from historical costs and anticipated needs, which are based on expected new generation connections, joint use projects, and future plans of Municipal and Provincial road authorities. Details of the investments are provided below.

Joint Use
This investment addresses upgrades or other changes made to Hydro One Distribution assets in order to accommodate the use of these assets by joint use partners. These partners may

include telephone or cable companies (communication circuits), municipalities (street lighting), local distribution companies, or generators connected to the distribution system.

The type of upgrade or change required may involve increasing pole class to accommodate changes in pole loading, and/or increasing pole height to obtain appropriate ground clearances for public safety. These activities may also carry the cost associated with premature retirement of in-service assets.

Cost sharing provisions in joint use agreements allow Hydro One Distribution to recover costs resulting from requests to accommodate new attachments to its poles.

Line Relocations

This investment addresses the work required to relocate assets in response to road modifications initiated by Provincial or Municipal Road Authorities, or in response to property development initiated by individual customers.

Hydro One Distribution occupies road allowances at no c ost. In return, it is required, on occasion, to install, relocate or reconstruct its facilities in order to accommodate the specific requirements of road authorities. Most commonly, this involves relocating lines to accommodate changes to roads, highways, and bridges.

The cost of the plant relocation is either fully or partially recoverable, depending on t he specific circumstances of each project.

Result:

The joint use and line relocation program will result in:

- Satisfying Hydro One Distribution's contractual and legal obligations, and
- Maintaining property rights for distribution lines located on road allowances.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	48.5	49.5	50.5	51.5	52.6	252.5
Operations, Maintenance & Administration and Removals (B)	6.0	6.1	6.2	6.4	6.5	31.2
Gross Investment Cost (A+B)	54.5	55.6	56.7	57.9	59.0	283.7
Recoverable (C)	(21.8)	(22.2)	(22.7)	(23.1)	(23.6)	(113.4)
Net Investment Cost (A+C)	26.7	27.3	27.8	28.4	28.9	139.1

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

Investment Category:

System Access	System Renewal	System Service	General Plant
100%	0%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Respond to customer requests related to joint use modifications or line relocations to the existing distribution system.
Operational Effectiveness	• Deliver improved system reliability by addressing ageing, degrading and/or substandard equipment as part of the project.
Public Policy Responsiveness	• Comply with contractual and legal obligations under the Public Service Work on Highways Act and Hydro One Distribution's Conditions of Service.
Financial Performance	• Cost savings are recognized by cost sharing the upgrades or renewal of the distribution system in response to customer requests.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Pole Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the pole population through planned replacements of end-of-life and/or substandard condition poles to sustain system safety and reliability.

Need:
The structural integrity of a distribution line is largely dependent on its pole supports. Hydro One Distribution owns approximately 1.6 million poles. As outlined in Exhibit D1, Tab 2, Schedule 1 approximately 180,000 poles have already exceeded the expected service life for poles. Over the next five years, an additional 140,000 poles will exceed the expected pole service life.

Poles that have reached the end of their life pose a significant risk to the safe and reliable operation of the distribution system. During storm conditions, poles that fail can sometimes trigger "cascading failures", which results in the destruction of a larger number of distribution system assets. By replacing end-of-life poles before they fail, these situations can be avoided.

In addition to concerns with demographics, Hydro One Distribution continues to address the subset of red pine poles that are demonstrating premature degradation.

Alternatives:
Alternative 1: "Do Nothing"
Wait for the pole to fail and replace only on a reactive basis, at a premium cost and with increased safety risks.

Alternative 2: "Status Quo"
Continue replacement of poles at historical average rate of replacement. This alternative is not recommended as it will cause an unacceptable increase in pole related safety risk and jeopardize Hydro One Distribution's ability to resource the pole replacement program in the future.

Alternative 3: "Increased Rate" (Recommended)
Replace poles at a rate that balances asset needs and resource availability. This alternative will limit the increase in risk to the reliability of the distribution system associated with poles.

Investment Description:
This program addresses the replacement of poles that are at end-of-life. Poles are inspected on a regular basis, and are identified and prioritized for replacement based on an asset risk assessment that considers factors such as: age, condition, and type.

Hydro One Distribution's plan is to gradually ramp up the number of poles replaced each year, as outlined below, to allow for a sustainable increase in the resource levels required to complete these replacements.

Year	**2015**	**2016**	**2017**	**2018**	**2019**
Number of Pole Replacements	11,600	12,200	13,200	14,200	15,200

Depending on the types of poles requiring replacement (i.e. pole height, pole class, number of circuits, etc.) and the location conditions of the area the cost of installation can vary. Where possible, the efficiency of this investment is maximized by bundling work and replacing poles in close proximity to each other. If a very large number of poles are to be replaced as part of a single project, their replacement is funded by the "Large Sustainment Initiative" program as outlined in Investment Summary Document S12 in Exhibit D2, Tab 2, Schedule 3.

Result:
The pole replacement program will result in:
- Mitigating end-of-life issues,
- Reducing safety and reliability risks on the distribution system, and
- Ensuring compliance with utility standards, and regulatory and legal requirements.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	88.7	95.1	105.0	115.2	125.8	529.8
Operations, Maintenance & Administration and Removals (B)	12.1	13.0	14.3	15.7	17.2	72.3
Gross Investment Cost (A+B)	100.8	108.1	119.3	130.9	143.0	602.1
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	88.7	95.1	105.0	115.2	125.8	529.8

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers by proactively replacing wood poles prior to failure.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading wood poles.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by replacing ageing and degrading wood poles prior to failure event. • Comply with CSA standard by replacing wood poles that have deteriorated to 60% of their design strength.
Financial Performance	• Cost savings are recognized when wood poles are replaced proactively rather than reactively; as failed wood poles take longer to replace making it more costly. It also reduces the work bundling opportunities.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Lines PCB Equipment Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To manage the removal of line equipment with insulating oil containing polychlorinated biphenyls ("PCBs") in compliance with Environment Canada regulations.

Need:
Hydro One Distribution owns and operates approximately 450,000 pole top transformers and approximately 2,000 pole mounted capacitor units. Oil-filled equipment manufactured prior to 1985 may contain chemical compounds known as PCBs. In 2008, Environment Canada enacted legislation mandating the removal of all pole top equipment whose insulating oil contains greater than 50 ppm of PCBs by 2025.

All pole top transformers manufactured prior to 1985 will require oil sampling and PCB analysis as described in Exhibit C1, Tab 2, Schedule 2. From past experience with PCB testing, Hydro One Distribution projects that approximately 8% of these transformers will exceed the 50 ppm threshold and will ultimately require replacement due to PCB contamination. Capacitor units cannot be tested for PCBs without causing them significant damage, therefore all capacitors manufactured before 1985 will require replacement. The removal of PCB contaminated equipment is required to ensure health and safety risks are mitigated and ensure compliance with environmental legislation.

Alternatives:
No alternatives are considered, since failure to remove PCB contaminated line equipment would place Hydro One Distribution in violation of Environment Canada regulations. Replacement at a faster rate would result in unnecessary resource requirements in the short term. Replacement at a slower rate would require a large spike in volumes in the final years of the program to meet the 2025 deadline. Either case would introduce unnecessary and costly variations in the resource levels required to complete this program.

Investment Description:
This program addresses the removal and replacement of pole top equipment whose insulating oil contains PCB contamination levels greater than 50 ppm. Of the approximately 450,000 pole top

transformers in the distribution system, approximately 240,000 were manufactured prior to 1985 and must be tested for PCB contamination. Of these, Hydro One Distribution expects that approximately 19,000 will require replacement.

The replacement of transformers lags the PCB testing program by one year, allowing time for the identification of contaminated transformers and the planning required to replace them with minimal impact to customers.

Hydro One Distribution’s plan is to gradually increase the replacement rate over the first few years of the program, as outlined below. This will allow time to optimize the inspection, testing and removal processes. The ultimate replacement level is expected to be approximately 2,200 per year. This rate of replacement minimizes impacts to required resourcing levels and ensures the program will be complete by the 2025 deadline set out by Environment Canada.

Year	**2015**	**2016**	**2017**	**2018**	**2019**
Number of Pole Top Transformer Replacements	400	1,000	2,200	2,200	2,200

This program will also address the removal of all capacitor units manufactured prior to 1985. The specific units to be replaced will be identified by either the distribution line patrols or the PCB equipment inspection program.

Result:
The lines PCB equipment replacement program will result in:
- Mitigating health and safety risks associated with PCB contaminated line equipment, and
- Ensuring compliance with environmental legislation.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	1.9	5.0	10.6	10.8	11.1	39.3
Operations, Maintenance & Administration and Removals (B)	0.3	0.7	1.6	1.6	1.6	5.8
Gross Investment Cost (A+B)	2.1	5.7	12.2	12.4	12.7	45.1
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	1.9	5.0	10.6	10.8	11.1	39.3

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Mitigate potential health and safety hazards to customers and the public by minimizing the PCB oil contamination levels in lines equipment.
Operational Effectiveness	• Ensure continuous improvement of distribution lines by replacing the old PCB contaminated equipment with new equipment built to current standards and compatible with future loading requirements.
Public Policy Responsiveness	• Comply with Environment Canada legislation to remove all oil filled equipment with PCB contamination > 50 ppm by 2025.
Financial Performance	• Failure to complete the mandated PCB elimination by 2025 w ould result in non-compliance penalties.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Lines

Investment Name: Lines Sustainment Initiatives
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To refurbish entire feeders or sections of feeders on Hydro One's distribution system in order to address distribution assets approaching the end of their expected service life.

Need:
As outlined in Exhibit D1, Tab 2, Schedule 1, distribution line assets are ageing and a number of components are near or beyond the end of their expected service life. There are concerns with the condition of these assets, including wood poles, crossarms, and insulators. In some areas, our large customers' reliability is reaching unacceptable levels.

In addition to line assets reaching their end of expected service life, a number of component installations do not meet current Hydro One Distribution standards, including conductor sizing, framing, guying, transformer installations and clearance issues. These conditions pose increased safety and reliability risks.

These problems are further compounded when sections of feeders are located off-road and are difficult to access during power interruptions. Many of these lines require rebuilding or relocating to road allowances. Allowing these lines to remain in off-road sites would increase the risk of prolonged outages and safety concerns for the public and Hydro One Distribution personnel. The refurbishment of entire feeders or feeder sections is required in order to address these risks.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

<u>Alternative 2: "Individual Component Replacements"</u>
Replace individual defective assets on existing structures on a "like for like" component basis. While this type of replacement is performed in some cases, it is not ideal. Individual component replacements do not allow efficiencies associated with the replacement of large numbers of

assets in close proximity to each other. Further, replacing individual components would not address any accessibility concerns and would result in higher ongoing maintenance costs. Finally, "like for like" replacements of current components may require custom-engineered designs not following current Hydro One Distribution standards.

Alternative 3: "Lines Sustainment Initiatives" (Recommended)
Refurbish or rebuild entire feeders or feeder sections to current Hydro One Distribution standards. This will improve the reliability of the distribution system and minimize any safety risks to the public and Hydro One Distribution personnel. Typically the cost of maintaining individual components in the circuit becomes excessive when there are a number of components near the end of their expected service life. By integrating line work to refurbish or rebuild entire feeders or sections, costs can be reduced.

Investment Description:
Distribution line assets deteriorate over time and should be replaced as they reach their expected end of service life. Taking into account the overall condition of poles, conductors and associated components; certain feeder sections have been identified for refurbishment or rebuild. Refurbishing or rebuilding an entire feeder section is preferred when the cost of maintaining or replacing individual components on that section becomes excessive.

There are a number projects identified under this program annually; which vary significantly in size and scope. The projects with capital investment exceeding $1 million are provided in the following table. Each of these projects involves equipment that is near or has exceeded their expected service life. Not proceeding with these investments would result in aged line installations remaining in service resulting in increasing risk of failure causing prolonged outages, reliability issues, and safety concerns.

Year	Project Name	Total ($M)
2015	Bailey's Corner DS F1 Rebuild, *Sudbury*	1.3
	Brant TS M21 Relocation, *Simcoe*	1.5
	Brockville TS 24M2 Relocation Phase 5 of 5, *Brockville*	2.0
	City of Owen Sound Refurbishment Phase 2 of 4, *Owen Sound*	2.3
	Duart TS M6 Relocation Phase 2 of 2, *Kent*	2.3
	Drymond TS M3 Rebuild, *New Liskeard**	6.0
	Manitouwadge TS M2 Rebuild, *Thunder Bay**	6.5
	Martindale TS 9M5 Relocation Phase 5 of 6, *Sudbury*	2.1
	Minden TS 87M2 Relocation Phase 1 of 6, *Minden*	4.1
	Otonabee TS 128M28 Relocation Phase 1 of 3, *Peterborough*	2.0
	Tilsonburg TS 20M10/Norfolk TS M3 Relocation, *Simcoe*	4.3
2016	City of Owen Sound Refurbishment Phase 3 of 4, *Owen Sound*	2.2
	Douglas Point TS Feeder Relocation, *Walkerton*	3.0
	Duart TS M5 Relocation, *Kent*	3.9
	Duart TS M6 Relocation, *Strathroy*	1.2
	Frontenac TS 8M3 Sub Cable Replacement, *Kingston*	1.6
	Kleinburg TS M8 Relocation, *Bolton*	2.0
	Martindale TS 9M5 Relocation Phase 6 of 6, *Sudbury*	1.6
	Minden TS 87M2 Relocation Phase 2 of 6, *Minden*	1.7
	Otonabee TS 128M28 Relocation Phase 2 of 3, *Peterborough*	1.2
	Reddendale DS Sub Cable Replacement, *Kingston*	1.5
	Terrace Bay Rebuild, *Thunder Bay**	4.0

** multi-year projects*

Year	Project Name	Total ($M)
2017	City of Owen Sound Refurbishment Phase 4 of 4, *Owen Sound*	2.1
	G3K Towerline Refurbishment, *Kirkland Lake*	1.0
	Kent TS M16 Relocation, *Kent*	1.2
	Larchwood TS M3 Relocation, *Sudbury**	5.0
	Manitoulin TS M25 Relocation, *Manitoulin*	1.5
	Minden TS 87M2 Relocation Phase 3 of 6, *Minden*	2.0
	Napanee TS 27M2 Relocation Phase 1 of 2, *Picton*	3.0
	Otonabee TS 128M28 Relocation Phase 3 of 3, *Peterborough*	1.5
	Sidney TS 12M7 – Back Up Supply, *Frankford**	6.0
	Sidney TS 12M7 – Wooler Rd. x Smithfield DS Relocation, *Frankford*	1.3
	Wanstead TS M4 Relocation (Brigden DS) Phase 1 of 2, *Lambton*	1.0
2018	Havelock TS 57M1 Apsley to Eel's Lake RS Relocation, *Bancroft*	3.5
	Havelock TS 57M2 Relocation Phase 1 of 2, *Tweed*	2.5
	Minden TS 87M2 Relocation Phase 4 of 6, *Minden*	2.0
	Morrisburg TS 18M26 Relocation, *Winchester*	4.0
	Napanee TS 27M2 Relocation Phase 2 of 2, *Picton*	3.0
	Picton TS 28M5 Relocation Phase 1 of 2, *Picton*	3.0
	Wanstead TS M4 Relocation (Brigden DS) Phase 2 of 2, *Lambton*	1.0
2019	Dobbin TS 20M6 Relocation, *Peterborough*	2.5
	Duart TS M24 Relocation, *Kent*	1.9
	Flynn's Corners DS F3 Phase 1 of 2, *Bancroft*	1.8
	Havelock TS 57M2 Relocation Phase 2 of 2, *Tweed*	2.5
	Lindsay TS D4M7 Relocation Phase 1 of 2, *Fenelon Falls*	2.0
	Longueuil TS 26M23 Relocation, *Vankleek Hill*	3.5
	Minden TS 87M2 Relocation Phase 5 of 6, *Minden*	2.0
	Picton TS 28M5 Relocation Phase 2 of 2, *Picton*	3.0
	Timmins 25 Hz Line Removals, *Timmins*	1.0
	Wallace TS 16M1 Relocation Phase 1 of 2, *Bancroft*	2.5
	Whitefish DS F1 Rebuild, *Sudbury*	1.8

Result:
Lines sustainment initiatives will result in:

- Efficiently addressing a large numbers of aged, substandard or poorly performing assets,
- Improving customer reliability, and
- Eliminating known safety hazards to the public and Hydro One Distribution personnel.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	33.4	39.5	42.9	46.5	47.3	209.6
Operations, Maintenance & Administration and Removals (B)	3.9	4.0	4.3	4.4	4.5	21.1
Gross Investment Cost (A+B)	37.3	43.5	47.2	50.9	51.8	230.7
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	33.4	39.5	42.9	46.5	47.3	209.6

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of planned outages on distribution lines that impact customer supply with the integrated approach to lines sustainment initiatives. In the case where off-road line segments are relocated to more accessible locations, customer interruption time would also be reduced.
Operational Effectiveness	• Maintain safe operation and reliability of the distribution system by addressing ageing and degrading lines equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading equipment prior to failure.
Financial Performance	• Cost savings are recognized when all ageing and degrading components along a section of line are replaced as part of the same project. If the line is moved to more accessible location; then cost savings are also achieved in the event of storms, as power restoration time is minimized.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Line Component Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the distribution overhead and underground line equipment through planned replacements to address end-of-life or defective equipment to ensure a reliable and safe distribution system.

Need:
Hydro One's distribution system consists of approximately 120,000 circuit kilometers across the province. Line patrols and preventative maintenance programs are used to assess the condition of line equipment. These assessments have identified a number of distribution line components that are near the end of their expected service life. Additionally, there are a number of components that are substandard or that pose environmental risks. These components, which include crossarms, nest platforms, overhead conductor, regulators, reclosers, sentinel lights, substandard transformers, and switches, must be replaced or refurbished to mitigate their associated risks.

Alternatives:
Alternative 1: "Do Nothing"
Wait for the distribution line equipment to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

Alternative 2: "Replace Assets" (Recommended)
Proactively replace distribution line equipment approaching end-of-life, demonstrating deteriorating condition or posing a safety risk to mitigate the risk of failure and ensure a safe and reliable distribution system.

Investment Description:
This program addresses the individual replacement or refurbishment of distribution line components when it is not economical to integrate the work into one of the large sustainment initiative projects. The program comprises the replacement of the following asset types:

Crossarms

Crossarms are fastened to poles to support insulators and conductors. As these components deteriorate with age, their risk of failure increases, posing increased safety risks to the public and Hydro One Distribution personnel, and impacting system reliability. By proactively addressing crossarms in poor condition, the risk of major crossarm failures can be greatly mitigated. The rate of replacement is approximately 2,500 crossarms per year, at a cost that ranges from $2.5 million to $2.7 million annually over the five year period.

Nest Platforms

Bird nests on distribution poles can potentially cause pole fires and damage equipment, impacting safety, asset condition, and system reliability. Nest platforms are constructed to allow bird nests to be relocated from distribution poles, while complying with environmental regulations protecting species at risk. The relocated nest platforms can be installed on existing poles, on taller poles, or on separate adjacent poles. The rate of relocation is approximately 30 nest platforms per year, at a cost that ranges from $240 thousand to $260 thousand annually over the five year period.

Overhead Conductor

Some types of overhead conductor have been found to pose increased safety risks requiring modified work practices. The presence of this conductor limits Hydro One Distribution's ability to work on poles and equipment, and can pose work issues for Joint Use Partners. Replacement is based on the location and joint use status of poles which support these conductor types. The cost ranges from $1.0 million to $1.1 million annually over the five year period.

Regulators and Reclosers

Regulators and Reclosers are integral components in the operation of the distribution system. Devices requiring replacement are those which are inoperable and where maintenance is not deemed feasible. Failed or inoperable regulators and reclosers can lead to disproportionately widespread and/or extended outage impacts. Proactively replacing or refurbishing these aged, deteriorated or defective assets can greatly reduce these risks. The rate of replacement is approximately 350 regulators or reclosers per year, at a cost that ranges from $3.0 million to $3.3 million annually over the five year period.

Sentinel Lights

Sentinel Lights are legacy equipment which provides dusk to dawn lighting for Hydro One Distribution customers. Hydro One Distribution is contractually obligated to maintain existing installations, which may include replacing failed fixtures or poles. This program also funds the removal of lights that are no longer required. The rate of replacement or removal is approximately 1,300 per year, at a cost that ranges from $370 thousand to $400 thousand annually over the five year period.

Substandard Transformers

Substandard Transformers are transformers which are housed in substandard enclosures. These include “Pole Transformer” units and “Transclosure” units. These transformers are in poor condition and provide inadequate operational clearances. As a result, any work on them can only be completed if they are taken out of service, which results in long outages. As these types of transformers are not currently part of Hydro One Distribution’s standards, limited supplies of spare parts can also result in extended outages if they fail. This program funds the replacement of these substandard transformers. The rate of replacement is approximately 100 transformers per year, at a cost that ranges from $2.4 million to $2.6 million annually over the five year period.

Switches

Switches are integral components in the operation of the distribution system. Overhead Air Break and Load Break switches requiring replacement are those which have failed or have operational issues that cannot be feasibly repaired. Failed or inoperable switches can lead to reduced operational flexibility as well as disproportionately widespread and/or extended outage impacts. Proactively addressing these aged, deteriorated, or defective assets can greatly reduce these risks. The rate of replacement is approximately 60 switches per year, at a cost that ranges from $2.0 million to $2.2 million annually over the five year period.

Result:

The line component replacement program will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets,
- Maintaining reliability of the distribution system, and
- Satisfying regulatory requirements.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	11.6	11.8	12.1	12.3	12.6	60.4
Operations, Maintenance & Administration and Removals (B)	2.5	2.6	2.6	2.7	2.7	13.1
Gross Investment Cost (A+B)	14.1	14.4	14.7	15.0	15.3	73.5
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	11.6	11.8	12.1	12.3	12.6	60.4

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

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers and mitigate potential safety hazards by proactively replacing defective, substandard or deteriorated distribution line components.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading distribution line components.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by replacing ageing and degrading distribution line components prior to failure. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Cost savings are recognized when distribution line components are replaced proactively rather than reactively; as failed components take longer to replace making it more costly.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Submarine Cable Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage submarine cables through planned replacement or refurbishment of end-of-life or deteriorating cable sections in order to mitigate safety and reliability risks.

Need:
Hydro One's distribution system contains approximately 11,000 submarine cables totaling about 3,500 circuit kilometers in length. These cables are used to traverse water when overhead crossings are technically or economically unfeasible. Distribution system patrols have found that many cables are deteriorating, particularly at the shoreline. Cables that are exposed at or near the shore can be damaged by the movement of water or ice and by human activity. This damage usually takes the form of abrasion or corrosion of the protective cable armour, which can lead to neutral failure or water ingress. Cables that are damaged or exposed at the shoreline can pose public safety hazards, as well as increased reliability risks, and require refurbishment or replacement.

Alternatives:
Alternative 1: "Do Nothing"
Wait for submarine cables to fail while in service and replace them on a r eactive basis, at a premium cost and with increased safety risks.

Alternative 2: "Replace Assets" (Recommended)
Proactively replace or refurbish submarine cables approaching end-of-life or demonstrating deteriorating condition to mitigate the risk of failure and ensure a safe and reliable distribution system.

Investment Description:
This program addresses the replacement or refurbishment of submarine cables that are damaged or that are exposed at the shoreline. Cables that meet these criteria are identified during distribution system patrols. If a cable is found to pose an immediate hazard, it is immediately

replaced under the "Trouble Call" program. If immediate replacement is not possible, these cables are temporarily repaired and scheduled for replacement or refurbishment.

Depending on the location and extent of damage to a cable, the submarine cable may require either a sectional repair or a full cable replacement. In the case of a sectional repair, damaged locations are identified and a new section is spliced into place. However, if the cable is severely damaged, is obsolete, has exhibited poor performance, or has required repeated repairs, it is completely replaced. This program will replace or refurbish approximately 220 submarine cable sections per year. This program also addresses the reestablishment of mechanical shoreline protection and the installation of warning signage for these cables.

Result:
The submarine cable replacement program will result in:
- Mitigating public safety and reliability risks, and
- Complying with the distribution system code and good utility practice.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	7.1	7.2	7.4	7.5	7.7	36.8
Operations, Maintenance & Administration and Removals (B)	1.0	1.0	1.0	1.0	1.0	5.0
Gross Investment Cost (A+B)	8.0	8.2	8.4	8.5	8.7	41.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	7.1	7.2	7.4	7.5	7.7	36.8

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers and mitigate potential public safety hazards by proactively replacing defective, substandard or deteriorated submarine cables.
Operational Effectiveness	• Maintain customer supply reliability by replacing defective, substandard or deteriorated submarine cables components.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by replacing end of life submarine cables prior to failure. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a patrol.
Financial Performance	• Cost savings are recognized when submarine cable sections are replaced proactively rather than reactively; as failed components take longer to replace making it more costly.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Meters

Investment Name: Meter Upgrades
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To manage the retail revenue meter population through planned upgrades to address equipment that no longer meets current standards or is obsolete; as well as to address the new regulatory requirements imposed by the Distribution System Code.

Need:
Hydro One Distribution currently owns and operates approximately 1.2 million retail revenue meters. There are several factors that can trigger the need to upgrade these meters; some of the key factors are listed below:

- Hydro One Distribution is utilizing communication platforms for its metering network that are becoming obsolete and are being phased out by telecom providers.
- Hydro One Distribution is accountable, based on the market rules, to upgrade wholesale meter installations to a retail revenue meter when customers decide to become a retail customer of Hydro One Distribution at seal expiry.
- Hydro One Distribution has acquired non-standard meter installations due to a boundary change or the outright acquisition of an LDC.
- Hydro One Distribution has a population of "dumb" demand meters lacking communication which require manual meter reading.
- Hydro One Distribution has a population of 600V self-contained meters that have expired seals.
- Hydro One Distribution is required by the Distribution System Code, to upgrade existing customer's demand meters to interval meters when the average annual monthly peak demand is equal to or greater than 1,000 kW. There is also a requirement to install demand meters for customers who exceed 150,000 kWh of energy consumption per year.

Alternatives:
No alternatives are considered, since this program represents the minimum level of work to satisfy Hydro One Distribution's operational requirements. Replacement of meters is critical to maintaining a reliable source of billing settlement data.

Investment Description:
This program addresses meter upgrades and efficiency improvements that are impacted in part by reseal dates, obsolescence and customer requests. The work includes, but is not limited to the following:

1) Upgrade approximately 34,000 devices (meters and collectors) to a new communication platform. The current communication platforms Hydro One Distribution uses, CDMA & GSM networks (Bell Mobility & Rogers respectively), for a variety of its metering telecom needs are becoming obsolete and are being phased out by telecom providers. To ensure ongoing communication to meet the daily Time of Use reporting obligations, Hydro One Distribution is required to upgrade this technology.
2) Upgrade wholesale meter installations or acquired non-standard retail meter installations to Hydro One Distribution's current retail revenue meter standard.
3) Upgrade about 7,500 "dumb" demand meters lacking communication with electronic demand meters. This will eliminate manual meter reading, assist in standardizing inventory, and increase efficiency in dealing with trouble calls and maintenance due to reduced number of meter types.
4) Upgrade approximately 1,000 600V self-contained meters, with expired seals, with new 120V meters. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, allows Hydro One Distribution to meet expired seal obligations, eliminates a reliance on a single source supply as like-for-like replacements are not readily available on the market, and assists in standardizing inventory.
5) Upgrade existing customer's meters to interval meters or demand meters when the energy consumption exceeds the thresholds set out in the Distribution System Code.

Meter upgrades driven by seal expiry will be prioritized and performed by the reseal deadline. Where feasible, meter upgrades are bundled with other programs.

Result:
The meter upgrade program will result in:
- Improving reliability due to self-monitoring and remote communication capability,
- Ensuring a reliable source of billing settlement data is maintainable,
- Complying with regulatory requirements, and
- Increasing customer satisfaction.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	10.0	15.8	18.8	16.1	5.0	65.7
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	10.0	15.8	18.8	16.1	5.0	65.7
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	10.0	15.8	18.8	16.1	5.0	65.7

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
100%	0%	0%	0 %

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Respond to customer requests to become a retail customer rather than wholesale customer; provide automated meter reading capability; and ensure a reliable source of billing settlement data is maintainable.
Operational Effectiveness	• Deliver improved system reliability by addressing ageing, degrading and/or substandard metering equipment.
Public Policy Responsiveness	• Comply with the Distribution System Code requirements to upgrade existing customer's meters to interval meters or demand meters when the energy consumption exceeds the thresholds. • Comply with IESO Market Rules to upgrade wholesale to retail meters at customer request.
Financial Performance	• Cost savings are recognized when meters are replaced proactively rather than reactively; as failed components take longer to replace making it more costly. Future cost efficiencies are also expected when dealing with trouble calls and maintenance due to reduced number of meter types resulting from standardizing of the meter inventory.

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Meters

Investment Name: Meter Inventory Sustainment
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To maintain an inventory of retail revenue meters and metering network components to support the in-service population of meters and ensure regulatory compliance.

Need:
Hydro One Distribution currently owns and operates approximately 1.2 million retail revenue meters. With an in-service asset base of this magnitude, it is expected that annually there will be a number of meters that will fail, get damaged, become obsolete, or will be retired due to reaching the end of expected service life. Furthermore, retail revenue meters that fail their routine verification of accuracy also require replacement as set out by the requirement of the *Electricity and Gas Inspection Act*. Based on recent operational experience approximately 18,000 retail revenue meters are required to be removed and replaced each year. Therefore, an inventory in addition to the in-service meters must be maintained in order to ensure the replacement of meters and metering network components is completed in a timely manner.

Alternatives:
No alternatives are considered, since this program represents the minimum level of work to satisfy Hydro One Distribution's operational requirements. Availability of replacement meters is critical to maintaining a reliable source of billing settlement data.

Investment Description:
This program focuses on m aintaining an adequate level of inventory in order to supply replacement retail revenue meters and network components in a timely manner. The inventory consists of: smart meters, demand meters, collectors, repeaters, meshgates, and other electronic components used in the metering network. The required inventory levels are determined based on the population size of particular meter or equipment model, historical failure rates, and planned sampling of meters for future years. The annual inventory purchases are dependent on which categories of equipment were deployed to replace failed equipment each year.

Result:
The sustainment of a meter inventory will result in:
- Ensuring timely availability of metering equipment,
- Complying with regulatory requirements, and
- Ensuring a reliable source of billing settlement data is maintainable.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	4.6	4.8	5.0	5.2	5.5	25.1
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	4.6	4.8	5.0	5.2	5.5	25.1
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	4.6	4.8	5.0	5.2	5.5	25.1

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

Investment Category:

System Access	System Renewal	System Service	General Plant
100%	0%	0%	0 %

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce customer interruption time by maintaining an adequate level of spare retail revenue meters and network components.
Operational Effectiveness	• Deliver improved system reliability by ensuring a reliable source of billing settlement data is maintainable.
Public Policy Responsiveness	• Comply with the *Electricity and Gas Inspection Act* by having sufficient inventory to replace retail revenue meters that fail their routine verification of accuracy in a timely manner.
Financial Performance	• Cost savings are recognized when dealing with trouble calls and maintenance through standardization of the meter inventory.

Hydro One Distribution – Investment Summary Document

Development Capital

Investment Name: New Connections, Service Upgrades and Metering
Work Execution Period: January 2015 to December 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To meet the on-going demand to connect new customers to Hydro One Distribution's network, upgrade services of existing customers, and the cancellation of service.

Need:
This is a demand driven program, as new services are provided in response to customer requests. Each year, Hydro One Distribution is obligated to connect new customers to the distribution network; upgrade services for existing customers; and install meters for new services under Hydro One's Distribution License. These system investments include the following activities:

New Connections - As part of its obligations under Hydro One's electricity distribution license and the distributor's responsibilities in the Distribution System Code (DSC), Hydro One Distribution is required to make an offer to connect all distribution customers on a non-discriminatory basis, upon written request for connection.

Service Upgrades - A service upgrade occurs when a customer requires a larger service entrance. A service upgrade normally requires the preparation of a service layout and replacement of secondary service wires. Transformers may also have to be upgraded, meters replaced and possibly additional transformation installed.

Metering - Installations may be required for new connections and service upgrades. Revenue meters, previously funded under the smart meter program, are funded under this program for new connections and service upgrades.

Cancellations - For cancellations of existing service, Hydro One Distribution is required to remove idle assets (such as transformers, poles, wires and meters) for safety and security reasons. The cost for this work is treated as depreciation expense, where most other costs associated with new connections and upgrades are capitalized.

Not proceeding with these investments would result in non-compliance with Distribution license requirements and with obligations under the Distribution System Code. This work is a regulatory requirement.

Investment Description:
Individual investments within these programs are managed on a project basis. Projects include design (service layouts), labour, material and other costs associated with actual physical connection or removal.

A standard connection consisting of a service layout, overhead transformation, 30 m of overhead conductor, and standard retail metering (including smart meters) is provided free of charge to new customers that "lie along" the existing network, as per the DSC requirements. For customers that require expansion of the network in order to be connected, a discounted cashflow calculation is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection and network expansion. Per Section 3.3.3 of the DSC, a capital contribution is no longer required for enhancement of the network. Customer contributions for system expansions, plus other recoverable costs beyond the standard connection, are forecasted to be between $30.2M and $34.1M between 2015 and 2019. Projected costs for these programs are primarily based on historic demand and forecast load growth that takes into consideration the Ontario Gross Domestic Product and Ontario Building Permits.

Service cancellations are included in this program's gross investment costs. These involve customers who request disconnection from the distribution system. Hydro One Distribution removes idle assets, such as transformers, poles, service wires and meters for safety and security reasons. As this work involves the removal of Hydro One Distribution owned equipment, these costs are accounted for under depreciation and are not capitalized. They are therefore not identified in this program's Capital and Minor Fixed Assets costs (Line "A" in the Cost table below).

The actual and projected volume (number of units) of New Connections, Service Upgrades and Service Cancellations from 2015 to 2019 is summarized in the table below.

Description	2015	2016	2017	2018	2019
New Connections	15,530	15,570	15,850	16,010	16,170
Service Upgrades	4,554	4,604	4,654	4,704	4,744
Service Cancellations	6,230	6,300	6,360	6,420	6,490

Result:

- Connect new customers and satisfy the requirements of the Distribution System Code and Distribution License.
- Upgrade the services of existing customers.
- Remove assets when services are cancelled and mitigate safety risks.
- Satisfy the requirements of the Distribution System Code and Distribution License.

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	139.0	143.2	147.9	152.4	157.0	739.5
Operations, Maintenance & Administration and Removals (B)	9.3	9.6	9.9	10.2	10.5	49.5
Gross Investment Cost (A+B)	148.3	152.8	157.8	162.6	167.5	789.0
Recoverable (C)	(30.1)	(31.1)	(32.1)	(33.1)	(34.1)	(160.5)
Net Investment Cost (A+C)	**108.9**	**112.1**	**115.8**	**119.3**	**122.9**	**579**

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

Investment Category:

System Access	System Renewal	System Service	General Plant
100%	0%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Respond to customer requests for connections and upgrades within established time frames and with a high level of customer satisfaction.
Operational Effectiveness	• Ensure all new connections or upgrades meet latest standards and remove assets when services are cancelled to mitigate safety risks.
Public Policy Responsiveness	• Comply with requirements in the DSC and Distribution Licence to provide new connections or service upgrades when requested by customers.
Financial Performance	

Hydro One Distribution – Investment Summary Document

System Capability Reinforcement

Investment Name: System Upgrades Driven by Load Growth
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To provide adequate supply to accommodate system load growth on the distribution system with new or modified distribution facilities.

Need:
Over time, customer connections accumulate and place additional stress on distribution system elements. Increases in feeder loading can lead distribution system elements, such as conductors, transformers, regulators and switches, to operate at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load.

In accordance with Section 3.3 of the Distribution System Code, Hydro One Distribution plans and executes enhancement projects on its distribution system to improve system operating characteristics and relieve system capacity constraints. These projects are developed considering the cost-benefits and long-term planning advantages of potential alternatives. The alternatives considered typically involve increasing capacity at distribution stations by upgrading equipment, constructing new stations, constructing new feeders to provide relief to over-loaded feeders, extensions to or reconfigurations of existing feeders to allow them to operate within acceptable ranges, and voltage conversions to increase feeder capacity.

Not relieving heavily loaded equipment will lead to equipment failure and damage, jeopardizing safety, reliability and customer risks.

Further details and a listing of the planned projects from 2015-2019 are found under Investment Description below.

Investment Description:
There are a variety of ways to relieve overloaded equipment. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Feeder Reinforcement: One common solution is to redistribute load through reinforcement projects. These projects focus on optimizing load distribution by reconfiguring existing feeders to enable load transfers. By extending feeders, installing new phases and tie points, and updating feeder protections, lightly loaded feeders can offload heavily loaded sections.

Station Upgrade: Station upgrade projects are executed in areas where the existing configuration cannot be utilized to offload equipment that has reached its planned loading limit. Instead, additional capacity must be added to the system. S tation upgrades involve an increase in capacity to existing stations by upgrading transformer sizes; installing additional transformers; increasing the station's secondary voltage (voltage conversion at the station); or installing fan monitoring to cool station transformers. These projects also include adding new feeder positions at the station to increase the number of available feeders.

Construct New Station: In some situations, constructing a new station is more effective from a cost and operating perspective than upgrading an existing station. In these cases, a new distribution station is installed and incorporated into the distribution system. N ew feeders are also used to provide additional capacity to areas that are overloaded. These feeders may be built to compliment the construction of a new distribution station.

Voltage Conversion: To increase equipment ratings and capacity, feeders may also be converted to higher voltage levels. These upgrades may conincide with a station voltage conversion or may involve a reconfiguration with nearby feeders that operate at higher voltage levels.

To ensure system elements remain within their acceptable operating ranges the following investments are planned. These projects are reprioritized each year as new loading information and updated forecasts become available to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects with cash flow greater than $1 million in any of the test years are listed below:

2015 Projects	Total $M
Brown Hill TS New Feeder Development, Queensville, *East Gwillimbury*	3.5
Clark TS M2 Feeder Reinforcement, *Ilderton*	2.1
Commerce Way TS M3 Feeder Reinforcement, *Woodstock Surrounding Area*	2.1
Courtice DS Upgrades, Courtice, *Clarington Township*	3.0
Courtice DS Voltage Conversion, *Courtice, Clarington Township*	1.8
Grand Bend East DS Upgrades, *Grand Bend, Zurich & Dashwood*	1.0
Manotick DS New Feeder Development, *Manotick, City of Ottawa*	2.6
Nobleton DS Upgrade, Nobleton, *King Township*	3.0
Owen Sound TS M28 Feeder Reinforcement, *Northern Bruce Pennisula*	1.0
Total	**20.1**

2016 Projects	Total $M
Allanburg TS M7 Feeder Reinforcement, Thorold	1.0
Ancaster West DS Upgrades, Anacaster, City of Hamilton	2.0
Armitage TS M22 Feeder Reinforcement, Stouffville & Whitchurch	1.9
Beckwith DS Upgrades, South of Carleton Place (Mississippi Mills)	2.2
Brown Hill TS M4 Feeder Reinforcement, Georgina Township	1.9
Burleigh DS F2 Feeder Reinforcement, East of Fort Frances	1.0
Devlin DS F1 Feeder Reinforcement, Devlin	1.0
Dobbin DS F1 Feeder Reinforcement, Township of Cavan Monaghan	1.0
Grand Bend East DS F3 Feeder Voltage Conversion, Grand Bend & Surrounding Area	2.4
Stouffville 10th Line DS Upgrade, Stouffville & Whitchurch	3.0
Massey DS F3 Feeder Reinforcement, North Shore Algoma	1.0
New Station - Twelve Mile Bay DS, Georgian Bay	3.0
Point Au Baril DS F2 Feeder Reinforcement, Bayfield Inlet/Britt	3.6
Twelve Mile Bay DS Submarine Cables, Georgian Bay/ Honey Harbour	1.4
Total	**26.4**

2017 Projects	Total $M
Arnprior Elgin DS Upgrades, Arnprior	1.0
Arnprior Zervos, Reid & Madawaska DSs Reinforcement, Arnprior	1.0
Awenda DS F1 Feeder Reinforcement, Christian Island (Beausoleil First Nation)	3.6
Beaverton TS M29 Feeder Reinforcement, Uxbridge	1.6
Beckwith DS F3 Feeder Reinforcement, South of Carleton Place (Mississippi Mill)	1.8
Dunchurch DS F2 Feeder Reinforcement, Magnetawan	2.8
Kenilworth DS Upgrade, Northern Wellington County	2.5
Kingsville/Leamington Feeder Reinforcement, Kingsville/Leamington	1.8
Lindsay TS D4M7 Feeder Reinforcement, Bobcaygeon	4.0
New Station - Uxbridge RS #2, Uxbridge	2.0
Orangeville TS M3 Feeder Reinforcement, Caledon	1.8
St. Lawrence TS M27 Feeder Reinforcement, West of Cornwall	2.0
Woods DS Voltage Conversion, Kirkland Lake	2.6
Total	**28.5**

2018 Projects	Total $M
Armitage TS M42 Feeder Reinforcement, King Township	1.6
Colpoys Bay DS F2 Feeder Reinforcement, Northern Bruce Pennisula	1.0
Greely DS New Feeder Development, City of Ottawa	1.3
King City DS New Feeder Development, King Township	1.8
Kingsville/Leamington Feeder Reinforcement, Kingsville/Leamington	4.4
Kirkland Lake DS #1 Voltage Conversion, Kirkland Lake	2.0
Muskoka TS M1 Feeder Extension, Muskoka Lakes	5.3
New Station - King City DS, King Township	3.0
New Station - Old School DS, Mayfield, Southern Caledon	3.0
New Station - Stouffville RS, Stouffville & Whitchurch	2.0
Old School DS New Feeder Development, Mayfield, Southern Caledon	1.8
Rockland DS Upgrades, Rockland	2.6
Stratford TS M6 Feeder Reinforcement, City of Stratford	1.0
Total	**30.8**

2019 Projects	Total $M
Emsdale DS F2 Feeder Reinforcement, Kearney	2.1
Ferndale DS F2 Feeder Reinforcement, Northern Bruce Pennisula	2.1
Goodfish DS Voltage Conversion, Kirkland Lake	2.8
Kenilworth DS Feeder Reinforcement, Northern Wellington County	1.8
Kleinburg TS M26 Feeder Reinforcement, Caledon	3.2
New Station - Mar DS, Northern Bruce Pennisula	3.0
New Station - Mount Albert DS #2, East Gwillimbury	4.0
New Station - Port Elgin North DS, Saugeen Shores	3.0
New Station - Woodbine DS, East Gwillimbury	3.0
Puslinch DS New Feeder Development, Wellington County	2.6
New Station - Wilson Rd DS, Springwater Township	3.5
Woodbine DS New Feeder Development, East Gwillimbury	1.8
Total	**32.9**

Result:

- Balance loads to allow for additional customer connections and to improve voltage and power quality
- Reduce line losses
- Mitigate reliability risks and minimize potential safety hazards associated with overloading system equipment
- Maintain voltage and power quality levels to within standards and mitigate customer dissatisfaction
- Provide additional supply options to relieve overloaded feeders and enable future load growth and customer connections

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	20.1	26.4	28.5	30.8	32.9	138.7
Operations, Maintenance & Administration and Removals (B)	1.8	2.2	3.1	2.8	2.2	12.1
Gross Investment Cost (A+B)	21.9	28.6	31.6	33.6	35.1	150.8
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	20.1	26.4	28.5	30.8	32.9	138.7

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Maintain proper voltage levels and power quality for customers as well as reducing line losses.
Operational Effectiveness	• Improve or maintain reliability in areas that require reinforcement due to load growth or connection of renewable generators.
Public Policy Responsiveness	• Provide system enhancements where required to facilitate load and generation customers and meet DSC requirements.
Financial Performance	• Cost savings are realized when ageing and degrading components on the system are replaced with new and modern equipment.

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Upgrades Driven by Load Growth - Distribution System Modifications
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To provide adequent supply to accommodate system load growth on the distribution system with new or modified distribution facilities.

Need:
This investment covers projects focused on correcting feeder load balance, voltage quality and protection coordination issues that arise over time due to natural load growth and economic changes. As these changes occur, the distribution of load along feeders can vary significantly. This can affect the voltage quality and conductor loading; cause improper protection operations; and potentially cause equipment ratings to be exceeded. To identify any issues that have arisen, the distribution system is reviewed on a cyclical basis.

Not proceeding with this investment increases reliability and safety risks associated with low feeder end voltages, overloaded equipment, and improper protection operation. It also increases the risk of not adhering to industry standards for voltage regulation and current levels.

Alternatives:
Annual investments on each feeder are not recommended because year over year the changes to load distribution are relatively minimal and this alternative does not lead to the most efficient use of resources.

A review cycle longer than six years is not recommended because the investment needs resulting from natural load growth and economic changes would not be addressed in a timely manner. This would significantly increase the risk of operating the distribution system with overloaded equipment, voltage issues and improper protection.

The recommended six-year review cycle length is a balance between addressing natural load growth in a timely manner and effectively applying resources to maintain all distribution feeders at appropriate voltage and protection levels. This aligns with Hydro One's 6 year inspection cycle mandated by the Distribution System Code, Appendix C.

Investment Description:
The work performed under this investment is coordinated with feeder studies which are conducted on a six-year cycle through Development OM&A activities (Exhibit C1, Tab 2, Schedule 3). The investments address the needs identified through the studies and are executed through this program on a priority basis.

To correct feeder load balance, voltage quality and protection coordination issues, the scope of work involved can include rebalancing and rephrasing feeders, changes to feeder configuration, new or modified protection equipment and voltage regulators, feeder expansions, construction of new feeders and voltage conversion.

Separate scopes of work are developed for each distribution station and their downstream feeders based on the results of feeder studies. Each project under the Distribution System Modifications costs less than $1M each year so they are not listed separately. Work is prioritized based on the severity and criticality of the issues being addressed.

Result:
- Mitigate reliability and safety risks associated with improper protection coordination, overloaded equipment, and non-standard voltage levels
- Mitigate customer power quality issues
- Maintain system voltage and current levels within industry standards
- Improve operational efficiency with effective protection schemes

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	9.0	9.2	9.4	9.1	8.8	45.6
Operations, Maintenance & Administration and Removals (B)	1.2	1.3	1.3	1.2	1.2	6.2
Gross Investment Cost (A+B)	10.2	10.5	10.7	10.3	10.0	51.8
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	9.0	9.2	9.4	9.1	8.8	45.6

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
-	-	100%	-

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Maintain voltage levels and power quality and adjust protection settings to minimize power interruptions to customers.
Operational Effectiveness	• Improve operational efficiency by addressing overloading on parts of the system, proper phase balancing and ensuring effective protection schemes to deal with changes on the system.
Public Policy Responsiveness	• Maintain system voltage and current levels within industry standards.
Financial Performance	• Cost savings are realized when ageing and degrading components are replaced with new and modern equipment.

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Upgrades Driven by Load Growth - Demand Investments
Work Execution Period: January 2015 to December 2019
Primary Outcome: Customer Focus

Objective:
Minor distribution system modifications are required to address system needs identified by customer power quality complaints, feeder studies and system impact assessments. Responding to these needs ensures an adequate supply of electricity to customers.

Need:
This investment resolves lower cost, high priority issues identified by customers, feeder studies, or system impact assessments with a short lead-time. These issues arise on a demand basis and typically relate to power quality, and feeder protection. As these issues arise on the distribution system, it is imperative for Hydro One Distribution to address them in an expedient and efficient manner.

Not proceeding with this investment would result in critical issues remaining on the system, leading to deteriorated service reliability and power quality, decreased customer satisfaction and substandard supply. Damage to distribution system assets could also occur.

Investment Description:
Technical criteria are used in assessing system and customer needs. Minor system modifications or betterments addressed by this plan include items such as protection coordination, and installing new equipment or equipment upgrades. As the type of issues that need to be resolved in this program are unforeseen, this work is considered demand and annual costs are based on historic spending. These investments generally cost between a few thousand dollars and a few hundred thousand dollars.

Result:
- Maintain reliability and quality of service within supply standards
- Address customer issues in an expedient and efficient manner

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	3.6	3.7	3.8	3.4	3.4	17.9
Operations, Maintenance & Administration and Removals (B)	0.5	0.5	0.5	0.5	0.5	2.5
Gross Investment Cost (A+B)	4.1	4.2	4.3	3.9	3.9	20.4
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	3.6	3.7	3.8	3.4	3.4	17.9

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

Investment Category:

System Access	System Renewal	System Service	General Plant
-	-	100%	-

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• High priority issues identified by customers are dealt with and resolved to ensure ongoing customer satisfaction.
Operational Effectiveness	• These investments ensure that protection settings are effective and power quality is within acceptable levels for customers.
Public Policy Responsiveness	• As per the DSC, Hydro One is required to maintain reliability and power quality standards by addressing issues identified in feeder studies or system impact assessments.
Financial Performance	• Cost savings are realized when equipment causing issues on the system is replaced proactively and not after damage to distribution or customer assets has occurred.

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Asset Life Cycle Optimization and Operational Efficiency
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To improve operations and asset life cycle planning with additions or upgrades to the distribution system.

Need:
As assets reach end-of-life, the risk of failure under adverse conditions increases, which can lead to lengthy interruptions to customers and can increase the likelihood of exposing the employees and the public to safety hazards. In areas where other issues are also present, such as poor voltage levels and limited load transfer capability, it is often beneficial to address all issues through one project that upgrades or modifies the existing configuration.

Not proceeding with this investment would result in higher expenditures, reduced productivity and inefficient operations. The issues addressed under this investment are a mix of urgent needs and good planning practices that improve overall system operations. By executing projects that simultaneously address these items over individual refurbishment or upgrade projects, overall costs are reduced and fewer resources are required.

Investment Description:
Assets at the end of their expected service life are typically addressed by sustainment projects and programs that focus on like-for-like replacements. However, in some situations it is more efficient from a cost and operations perspective to simultaneously address end-of-life assets and improve operational efficiency by upgrading or modifying the end-of-life assets. In these cases, system capability reinforcement is the preferred option to address asset sustainment needs.

Examples of these types of projects include voltage conversions to eliminate distribution stations and improve system voltage, installing new supply points, or constructing feeders to transfer loads to a new transmission station to replace an existing station.

To improve operations and optimize asset life cycle costs, there are several types of projects that are commonly executed.

Station Decommissioning through Voltage Conversions: One approach to remove a station from service is to convert the voltage of its feeders to match its upstream voltage. For example, to decommission a 27.6kV - 8.32kV station, the 8.32kV feeders could be converted to 27.6kV, which removes the need for the station. This approach is advantageous because it addresses stations that are near end-of-life, and improves the voltage quality and capacity of the downstream feeders.

Station Decommissioning by Constructing New Station/Feeders: Another approach used to decommission stations is to construct new stations in their place. In some cases, a new station may suffice to replace multiple stations that are near end-of-life. These projects also include the construction of new feeders to take over the loads from stations planned for decommissioning.

Voltage Conversions to Address Equipment nearing End of Life & Operational Efficiency: These projects simultaneously address equipment nearing end-of-life and operational improvements through voltage conversions. These are advantageous because not only do they address the reliability and safety issues associated with equipment nearing its end-of-life, but they also improve voltage quality and the capacity of the downstream feeders.

Operational Efficiency Improvements: These are projects that improve operational efficiency, while simultaneously addressing equipment nearing end-of-life, reliability issues and/or accessibility restrictions.

To improve operations and optimize asset life cycle costs, the following projects are planned for the test years of 2015 through 2019. These projects are reprioritized each year to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects with cash follow above $1M are provided as follows:

2015 Projects	**Total $M**
44kV Extension to Coniston, *Sudbury*	2.8
Belle River DS Voltage Conversion, *Belle River*	1.1
Carlton Place DS Reconstruction, *Carlton Place*	1.3
Mattawa Voltage Converson, *Mattawa*	1.0
Nipigon DS & Red Rock DS Voltage Conversion, *Nipigon*	1.9
Total	**8.1**

2016 Projects	Total $M
Coniston TS Voltage Conversion, *Sudbury*	2.6
Margach DS F1 Voltage Conversion, *Lake of the Woods*	2.0
New Station - Mattawa HVDS, *Mattawa*	5.1
Total	**9.7**

2017 Projects	Total $M
Burford DS Voltage Conversion, *Burford*	1.4
Grand Bend Municipal DS F3 Voltage Conversion, *Grand Bend*	1.3
Hanmer TS Feeder Development, *Sudbury Valley East*	1.4
New Station - Manitou Lake DS, *Manitoulin Island*	3.0
Manitou Lake DS New Feeder Development, *Manitoulin Island*	1.8
Total	**8.9**

2018 Projects	Total $M
Alexandria East Boundary , Margaret, & Kenyon West DSs Voltage Conversion, *Alexandria*	1.8
Eugenia RS Relocation, *Grey County (Grey Highlands)*	1.4
Margach DS F3 Voltage Conversion, *Lake of the Woods*	1.0
Total	**4.2**

2019 Projects	Total $M
Blind River DS Voltage Conversion, *Blind River*	1.0
Clearwater Bay DS F2 Voltage Conversion Stage 3, *Lake of the Woods*	1.7
Perth Wilson DS, Sunset DS, North DS, Halton DS & Scotch Line DS Operational Efficiency Improvements, *Perth*	1.8
Total	**4.5**

Result:

- Replace substandard and end of service life equipment to mitigate reliability and safety risks
- Improve voltage and power quality levels and mitigate customer dissatisfaction risks
- Provide operating flexibility that can be used during planned outages or emergency situations to minimize power outages to customers
- Overall reduction in costs and resources by addressing multiple issues simultaneously
- Reduce line losses

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	8.1	9.7	8.9	4.2	4.5	35.4
Operations, Maintenance & Administration and Removals (B)	0.9	0.6	0.8	0.6	0.6	3.5
Gross Investment Cost (A+B)	9.0	10.3	9.7	4.8	5.1	38.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	8.1	9.7	8.9	4.2	4.5	35.4

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	50%	50%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve voltage and power quality levels to mitigate customer dissatisfaction risks and reduce line losses.
Operational Effectiveness	• Replace substandard and end of service life equipment to mitigate reliability and safety risks and provide operating flexibility that can be used during planned outages or emergency situations to minimize power outages to customers.
Public Policy Responsiveness	• Replace end of life or substandard equipment as required by the DSC.
Financial Performance	• Cost savings are realized by executing projects that simultaneously address a number of system needs rather than individual refurbishment or upgrade projects as overall costs are reduced and fewer resources are required.

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Reliability Improvements
Work Execution Period: January 2015 to December 2019
Primary Outcome: Customer Focus

Objective:
To improve reliability and power quality with system modifications and additions.

Need:
The majority of Hydro One Distribution's system is constructed in a radial configuration, with minimal opportunities to transfer load during outages. To improve overall reliability, investments focused on reconfiguring the system's layout are required. These projects can include new tie-lines between feeders to create loop feeds and alternative supplies, reductions in overall line exposure per feeder, increased sectionalizing, and installing lightning arrestors. The quality of power delivered to customers can be improved by upgrading conductor sizes or installing voltage regulating equipment.

Not proceeding with this investment would leave customers susceptible to longer and more frequent outages that are characteristic of radially configured lines. The risk of serving customers at unacceptable power quality levels will also increase. If left unaddressed, poor power quality can lead to equipment damage and sustained outages for customers.

Investment Description:
There are a variety of ways to improve system reliability. Each area is unique and the optimal solution varies area to area depending on the existing feeder configuration and the state of surrounding lines and stations.

Examples of these types of projects include installing loop-feeds to provide alternative supply capabilities, installing express feeders to critical supply areas to reduce line exposure and improving sectionalizing capabilities to minimize the impact of lengthy outages. These reliability investments typically occur in areas with a higher customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs). Further details and a listing of the planned projects from 2015-2019 are found under Investment Details below.

Constructing Alternative Supply Options & Improving Sectionalizing Capabilities: To minimize the duration of an outage experienced, customers can be temporarily supplied by alternative sources as the faulted section of line is addressed. This is typically achieved by connecting two or more feeder sections through tie-lines and ensuring that appropriate equipment is in place to enable switching over to the alternative supply. Improved sectionalizing capabilities help reduce the number of customers impacted by sustained power interruptions.

Reducing Line Exposure: By decreasing the circuit length of a feeder, the total amount of conductor exposed to the elements is lessened. This reduces the likelihood of that circuit experiencing a fault due to natural elements, such as trees.

Improving Power Quality through Line Upgrades: Power quality can be improved by increasing conductor sizes or installing voltage regulating equipment.

Installing Lightning Arrestors: Lightning arrestors are used to prevent power interruptions due to lightning strikes. These are installed on feeders that experience a high frequency of lightning storms.

The following projects are planned for the test years 2015 through 2019. These projects are reprioritized each year to ensure they are addressed in order of criticality. Funding may also need to be reallocated to unplanned projects to serve immediate needs for system capability reinforcement. In these cases, planned projects may be postponed to ensure the most efficient use of resources and funding. However the overall funding requirement of the system capability reinforcement investments in the test years will not be changed. Projects above $1M are provided below:

2015 Projects	Total $M
Allanburg TS M7 Feeder Upgrades, *Thorold*	1.0
Brant TS M14 Tie Line, St. George, *Brant County*	1.7
Total	**2.7**

2016 Projects	Total $M
2nd Ave East DS, 12th St West DS, & 24th St West DS Tie Lines, *Owen Sound*	1.0
Tilsonburg TS & Norfolk TS Tie Line, Village of Delhi, *Simcoe County*	1.0
Total	**2.0**

2017 Projects	Total $M
Orangeville TS Tie Line, *Caledon*	2.6
Total	**2.6**

2018 Projects	Total $M
New Feeder - Aylmer TS, *Aylmer*	1.6
Total	**1.6**

2019 Projects	Total $M
Brant TS M21 to Wolverton DS F1 Tie Line	1.2
Armitage TS M34 Line Extension	1.0
Total	**2.2**

Result:

- Provide operating flexibility and alternate supply lines that can be used during emergency situations and planned outages to minimize power outage durations to customers
- Provide additional sectionalizing capability to improve supply reliability in the area
- Reduce frequency of outages for customers by reducing line exposure
- Improve overall quality of customers' supply voltage by upgrading line sections and prevent outages caused by unacceptable voltage levels

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	2.7	2.0	2.6	1.6	2.2	11.1
Operations, Maintenance & Administration and Removals (B)	0.4	0.3	0.4	0.2	0.3	1.5
Gross Investment Cost (A+B)	3.1	2.3	3.0	1.8	2.5	12.6
Recoverable (C)	-	-	-	-	-	
Net Investment Cost (A+C)	2.7	2.0	2.6	1.6	2.2	11.1

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• These investments address areas where customers are experiencing below average reliability and system improvements are needed to restore customer satisfaction.
Operational Effectiveness	• Provide operating flexibility and alternate supply lines that can be used during emergency situations and planned outages to minimize power outage durations to customers. • Improve overall quality of customers' supply voltage by upgrading line sections and prevent outages caused by unacceptable voltage levels.
Public Policy Responsiveness	
Financial Performance	• These reliability investments typically occur in areas with a higher customer density because of the relative cost-benefits (i.e. more customers benefit from improved reliability in comparison to the investment costs).

Hydro One Distribution – Investment Summary Document

System Capability Reinforcement

Investment Name: Orleans TS Capital Contribution
Work Execution Period: January 2015 to December 2015
Primary Outcome: Public Policy Responsiveness

Objective:
To provide a capital contribution to Hydro One Transmission for the construction of a new DESN transformer station at Orleans TS to support rapid load growth in the community of Orleans, within the City of Ottawa.

Need:
Hydro One Distribution currently serves this area from three existing stations: Bilberry Creek TS, Wilhaven DS and Navan DS. The existing loads at Bilberry Creek TS and Wilhaven DS exceed their planned loading limits (PLL). Navan DS is also approaching its PLL.

Hydro One Distribution has received customer complaints about poor reliability in this area. Both Wilhaven DS and Navan DS are supplied by a single 115 kV circuit. Due to the heavy concentration of loads and the long length of the feeders, there are times when back feeds or alternate supply arrangements are not available during outages. This has resulted in several outages with little or no transfer capability.

Hydro One Distribution feeders supplying Orleans are currently heavily loaded and feeder loads are expected to increase due to the fast-growing local commercial and residential construction.

Not proceeding with this investment would result in the inability to supply new load, deteriorated reliability in the area and increased customer and reputational risks.

Alternatives:
<u>Alternative 1: Do Nothing</u>
This alternative is not recommended due to the urban customer complaints in the area. The poor reliability is further complicated by the utilization of a single source of supply, long feeders, and heavily loaded stations.

<u>Alternative 2: Build a new DESN Transformer Station and new feeders (Recommended Alternative)</u>

This alternative is recommended because a new DESN at Orleans TS would relieve the heavily loaded stations in the area, provide a redundant source of supply, reduce the length of distribution feeders and provide adequate supply capacity to support the anticipated load growth. This alternative would provide the optimum alternate supply capability for improved reliability for urban customers in the area.

Alternative 3: Build a new Distribution Station and new feeders
This alternative would reduce the length of distribution feeders and relieve heavily loaded stations in the area. However, this alternative is not recommended because the reliability would not improve significantly due to the lack of redundant Transmission supply.

Investment Description:
The new transformer station at Orleans TS will be supplied by two sources, via the D5A and H9A circuits. The new station will have two new 50/83 MVA transformers and a low voltage switchyard with eight feeder positions. The dual nature supply of Orleans TS will reduce outage durations and the number of customers affected during outages. Hydro One Distribution will construct seven new feeders out of the new Orleans TS to connect to the existing lines in the surrounding area. These new feeders will relieve the existing heavily loaded feeders and reduce the average load per feeder to increase customer reliability.

The new Orleans TS will be used by Hydro One Distribution (seven feeders) and Hydro Ottawa (one feeder). Both LDCs will be required to pay capital contributions to Hydro One Transmission. The capital contribution amounts listed in the Costs section below are considered preliminary and will be determined and finalized in accordance with the Transmission System Code.

Result:
- Increase transformation capacity to meet future load growth requirements in the community of Orleans
- Improve reliability of supply for customers in the area

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	21.0	-	-	-	-	21.0
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	21.0	-	-	-	-	21.0
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	21.0	-	-	-	-	21.0

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Will provide a dual supply to Orleans to reduce outage time and when converted to a DESN will also reduce number of outages which addresses customer complaints in this area.
Operational Effectiveness	• The new Orleans TS will shorten the length of feeders in the area and improve distribution system efficiency and reliability.
Public Policy Responsiveness	• Meet the requirements of the DSC and Distribution Licence to provide increased transformation capacity and distribution system modifications to meet future load growth in the community of Orleans.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Red Lake TS Capital Contribution
In-Service Year: 2015
Primary Outcome: Public Policy Responsiveness

Objective:
To provide capital contributions to Hydro One Transmission for upgrades required on the transmission system to accommodate the connection of a large load customer and other projected distribution system load growth supplied by Red Lake TS.

Need:
A large distribution load customer has requested 5.4 MW of supply from Red Lake TS and Hydro One Distribution's normal load growth at Red Lake TS is expected to increase by 2.4 MW over the next ten years. The available supply capacity is currently constrained by conductor clearance and voltage issues on the 115 kV Hydro One Transmission system. Both Hydro One Distribution and the load customer will contribute to the costs of these upgrades.

Not proceeding with this investment would result in the inability to meet forecast distribution normal load growth and increased customer and reputational risks.

Alternatives:
<u>Alternative 1: Do Nothing</u>
This alternative is not recommended because Hydro One Distribution would not be able to meet the supply needs of distribution normal load growth and the additional capacity requirements of the large distribution load customer.

<u>Alternative 2: Upgrade the Transmission E4D, E2R and VAR resources (Recommended Alternative)</u>
This alternative is recommended as the cost-effective solution to meet supply needs. The proposed plan is to increase capacity of the E4D and E2R circuits by raising some of the towers. The other upgrade is to install new capacitor banks at Red Lake TS, which will support voltage levels when generation resources in the area are unavailable.

<u>Alternative 3: Build a second Transmission circuit to support the load</u>
This alternative is not recommended and was rejected because the cost of building a second circuit would be in the range of $50-60 million, significantly more than the recommended alternative.

Investment Description:
The required upgrades include raising the Transmission towers on the E4D and E2R circuits and installing VAR capability on the system.

Further load increases at Red Lake TS would increase conductor sag on the E4D circuit and cause clearance issues. Raising towers along the E4D circuit will increase the circuit capacity to accommodate load growth at Red Lake TS.

The other constraint is the availability of VAR resources if local generation is lost. The proposed plan is to install new capacitor banks at Red Lake TS. Without these installations, customer loads may be rejected, upon the loss of generation in the area.

As a result, Hydro One Distribution will pay capital contributions for the upgrades completed by Hydro One Transmission. A portion of these contributions will be recovered from the distribution load customer who is requesting the additional 5.4 MW of supply. The capital contribution amounts provided in the Costs section below are preliminary and will be determined and finalized in accordance with the Transmission System Code.

Result:
- Increase load capability on E4D line and Red Lake TS to accommodate a large customer's request for connection and to meet other future Hydro One Distribution load requirements at Red Lake TS.

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	6.0	-	-	-	-	6.0
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	6.0	-	-	-	-	6.0
Recoverable (C)	4.2	-	-	-	-	4.2
Net Investment Cost (A+C)	1.8	-	-	-	-	1.8

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	Satisfy a large customer's request for connection in a timely manner and allow for new customers to connect in the future.
Operational Effectiveness	Installation of capacitor banks will provide voltage support during loss of generation to improve system performance.
Public Policy Responsiveness	Meet the requirements of the DSC and Distribution Licence by increasing load capability on the E4D line and Red Lake TS to accommodate a large customer's request for connection and to meet other future Hydro One customer load growth requirements at Red Lake TS.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Hanmer TS Capital Contribution
In-Service Year: 2016
Primary Outcome: Public Policy Responsiveness

Objective:
To provide capital contributions to Hydro One Transmission for the construction of a new DESN transformer station at Hanmer TS. This will address end-of-life assets and facilitate improvements to reliability and address the long term needs in the Valley East community in northeast Sudbury.

Need:
There are a range of needs to be addressed in the northeast Sudbury region including:

- Hydro One Transmission has identified the T2 and T3 transformers at Coniston TS to be at the end of their expected service life and in need of replacement.
- Martindale TS M6 feeder is in poor condition and has demonstrated very poor reliability. There are also accessibility issues as portions of the M6 feeder spans through countryside and a mining reserve.
- The Valley East community within the City of Greater Sudbury has experienced steady load growth in the past ten years and is expected to continue growing. Martindale TS M6 is presently loaded above its planned loading limit.
- Coniston TS currently feeds a 22 kV network, presenting unique issues of being an electrical island which cannot be supplied from any other source. 22 kV is an obsolete sub-transmission voltage which will not exist anywhere else in the province after 2015. All new 22 kV load connections in the past 20 years have been equipped with dual-voltage transformers for eventual operation at 44 kV.

The transmission issues at Coniston TS and Martindale TS presented an opportunity for Hydro One Distribution to review the Transmission Connection facilities and determine the most appropriate and cost-effective options for meeting needs in the area.

This investment provides the most cost effective solution for meeting the needs in northeast Sudbury. The new DESN at Hanmer TS provides an alternate solution to simply replacing assets in the area. Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area.

Alternatives:
Alternatives were developed in order to address the end-of-life, loading, and reliability needs identified for the study area.

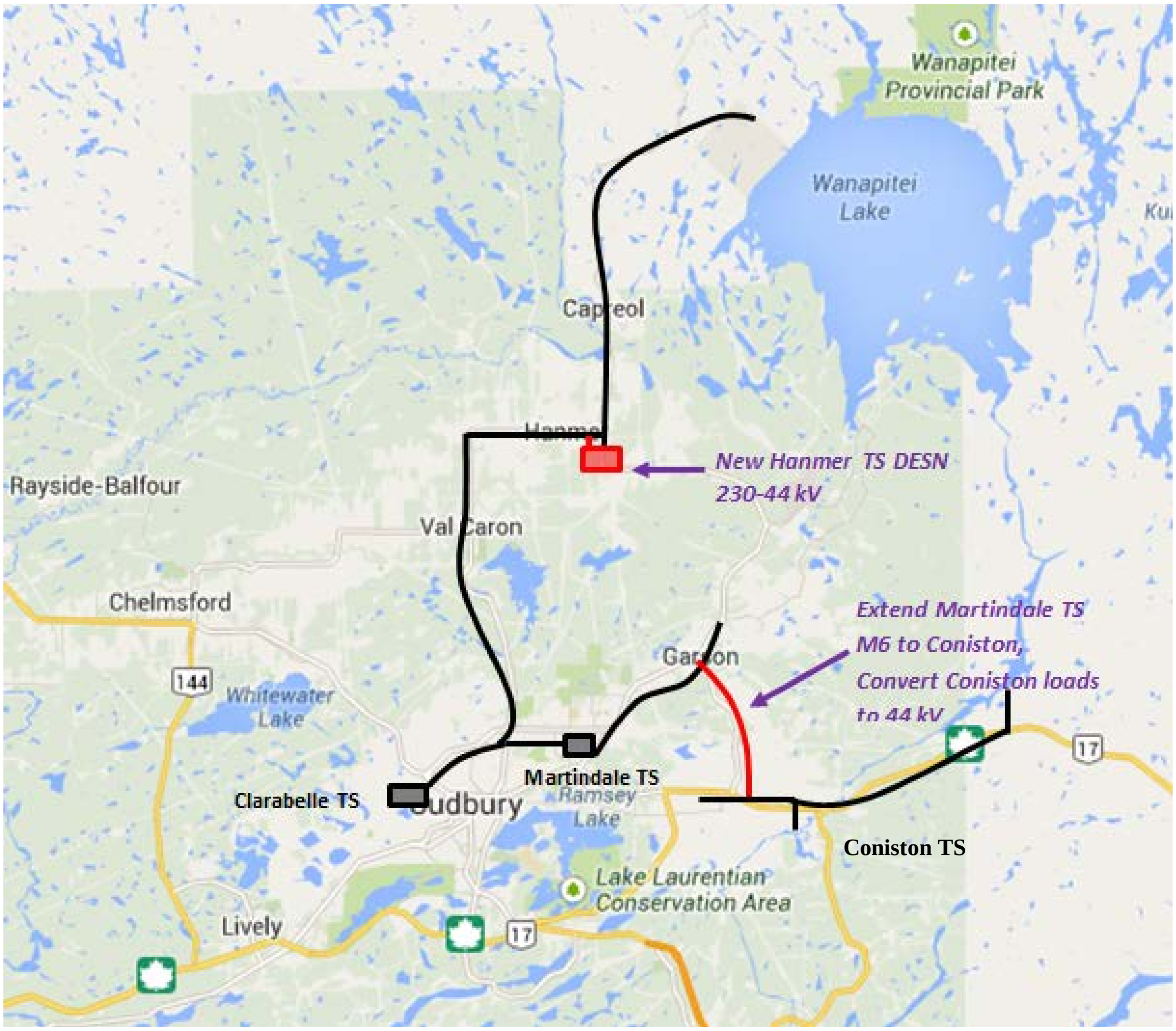
Alternative 1: Do Nothing
This alternative is not acceptable because it will not resolve the issues in the area. In addition to being one of the worst performing feeders in the province, sections of the Martindale TS M6 feeder are in poor locations and difficult to access. Coniston TS operates at 22 kV, an obsolete voltage level, and the two transformers are reaching their end of life. Clarabelle TS M7 and Coniston TS M1 are also of concern as they supply an urban area with a large number of commercial and industrial customers.

Alternative 2: Replace assets reaching their end of expected service life on a like for like basis
One alternative is to retain the existing system configuration and replace assets reaching their end of life. The transformers at Coniston TS could be replaced with new 22kV units. A new feeder could be built and double circuited with the M6 to address the overloading on t he Martindale TS M6. The Martindale TS M7 would be rebuilt double circuiting with Martindale TS M6 and Clarabelle TS M7. While this would be the less expensive replacement alternative, it is not recommended because retaining a 22 kV voltage is undesirable since it requires continued use of non-standard equipment leading to higher costs and limited suppliers. The shortage of supply of non-standard equipment often leads to prolonged outages. Not standardizing the voltage will eventually lead to deteriorated reliability and reduced operational efficiency in the area.

Alternative 3: Build a new DESN station at Hanmer TS (Recommended Alternative)
The preferred alternative is to build a new DESN station at Hanmer TS. This alternative costs approximately ten percent more than Alternative 2 but offers significant reliability, efficiency and operational improvements. Feeder lengths supplying the Hanmer area would be reduced from 12-14 km to about 2 km while line losses will be reduced by 40%. This alternative also allows for the elimination of the non-standard 22 kV operating voltage at Coniston and provides new connection capacity to accommodate forecast load growth in the area.

Investment Description:

The map below depicts the existing and proposed electricity transmission and distribution systems in the area:



The preferred solution is to construct a new 230-44 kV DESN at Hanmer TS, which is an existing 500kV – 230kV station connected to the Bulk Electricity System. The installation of a new 230kV - 44kV DESN at Hanmer TS would replace end-of-life feeder and station assets, improve reliability, and provide capacity to accommodate the load growth within the City of Greater Sudbury. This would provide Martindale TS with the capacity to service the Coniston area, removing the requirement to replace the assets reaching their end of service life at Coniston TS.

The existing Clarabelle TS M7 and Martindale TS M7 feeders and the Valley East Branch of the Martindale TS M6 feeder would be transferred to the new station. The placement of the new DESN would remove the requirement to rebuild the Martindale TS feeders reaching their end of expected service life. Hanmer TS would also provide new connection capacity in the Valley East load center, to better accommodate future load growth in the northeast Sudbury area. This solution would also eliminate Coniston TS by extending Martindale TS M6 and converting the load to 44kV.

The capital contribution amounts are considered preliminary and will be determined and finalized in accordance with the Transmission System Code.

Result:

- Increase transformation capacity to meet future load requirements
- Improve reliability of Martindale TS M6 feeder
- Improve operating efficiency by eliminating obsolete 22kV operating voltage from Coniston TS

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	-	11.5	-	-	-	11.5
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	11.5	-	-	-	11.5
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	-	11.5	-	-	-	11.5

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve reliability of the M6 feeder from Martindale TS to improve reliability of supply in the area and improve customer satisfaction.
Operational Effectiveness	• Improve operating efficiency by eliminating obsolete 22kV operating voltage from Coniston TS and by operating at 44kV to reduce line losses.
Public Policy Responsiveness	• Meet the requirements of the DSC and Distribution Licence to increase transformation capacity and provide distribution system modifications to accommodate future load growth in the Sudbury area.
Financial Performance	• Eliminating 22kV equipment results in cost savings by not having to stock non-standard equipment for 22kV.

Hydro One Distribution – Investment Summary Document

System Capability Reinforcement

Investment Name: Enfield TS Capital Contribution
In-Service Year: 2019
Primary Outcome: Public Policy Responsiveness

Objective:
To provide a capital contribution to Hydro One Transmission for the construction of the new Enfield TS to support the rapid load growth in the Region of Durham.

Need:
Wilson TS is currently operating above its limited time rating (LTR), and based on l oad projections, is expected to exceed its LTR by 150MW in the next twenty years. This is due to continued load growth in Oshawa and the Durham region, and from an expected 20-30 MW load increase for Ontario Power Generation's Darlington facilities in the next five years.

Not proceeding with this investment would result in overloading existing assets and the inability to accommodate future growth, and compromising reliability, safety and customer risks.

Alternatives:
Alternative 1: Do Nothing
This alternative is not recommended because Wilson TS is currently overloaded and is expected to exceed its capacity by a significant amount due to load growth and increased generation in the Durham region.

Alternative 2: Build new Enfield TS (Recommended Alternative)
The recommended solution is to build a new transmission station at Enfield TS to provide the capacity required to accommodate long-term growth. The feeders out of Enfield TS will also diversify the feeder routes and increase load transfer flexibility for improved outage response times and increased reliability in the region.

Alternative 3: Upgrade Wilson TS
The other alternative that Hydro One Transmission investigated is the expansion of the existing Wilson TS and building new distribution feeders. This alternative addresses the short-term capacity needs in the area. However, based on the load forecast, in another 10 years, the upgraded station would reach its capacity again and a second TS would be required to accommodate long term growth. This alternative would potentially result in extremely high costs

for the development of new distribution feeders. The surrounding area is already developed and congested with 16 feeders egressing from the station.

Investment Description:
The proposed plan is to build a new 230-44 kV 170 MVA transformer station at Enfield TS with eight 44 kV feeders shared between Hydro One Distribution and Oshawa PUC to serve the increasing needs in the Region of Durham and City of Oshawa. The overloading at Wilson TS will be addressed by utilizing four new Hydro One Distribution feeders and transferring some loads to Enfield TS. The new feeders will also improve reliability in the region by diversifying feeder routes. Additional load transfer options between Wilson TS and Enfield TS will reduce the number and duration of outages.

The new Enfield TS is to be utilized by Hydro One Distribution (four feeders) and Oshawa PUC (four feeders). Each distribution company is required pay its portion of the capital contributions to Hydro One Transmission. The capital contribution amounts provided under the Costs section of this document are considered preliminary and will be determined and finalized in accordance with the Transmission System Code.

Result:
- Increase transformation capacity to meet future load growth requirements
- Improve supply reliability by increasing redundancy of transmission supply

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	-	-	-	-	11.1	11.1
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	-	-	-	11.1	11.1
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	-	-	-	-	11.1	11.1

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Increase reliability of supply to existing customers and accommodate connection of future customers in the Durham area.
Operational Effectiveness	• Improve supply reliability by increasing redundancy of transmission supply and by diversifying feeder routing to allow for better load transfer capability and reduced number and duration of outages.
Public Policy Responsiveness	• Meet the requirements of the DSC and Distribution Licence to provide increased capacity to meet rapid load growth in the Region of Durham and to accommodate 20-30 MW of higher load at the Darlington station.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Development Capital – Generation Connections

Investment Name: Recloser Retrofit Project
Work Execution Period: January 2014 to December 2015
Primary Outcome: Operational Effectiveness

Objective:
To upgrade line reclosers and associated protections at 14 locations to meet current Hydro One standards.

Need:
During the connection of early distributed generators (DG), existing line reclosers that were upstream of the DG connection, could not be upgraded to include transfer trip to the DG because there was no engineering standard in place for the required work. The DG connection work was completed without upgrading the recloser installations. This resulted in these reclosers being unable to clear downstream faults. The station breakers of the 14 feeders are tripping at an increased rate due to the current line protection configuration which has the station breakers providing the fault and anti-islanding protection. Based on this issue and an increasing number of customer complaints, Hydro One developed the necessary engineering standards to upgrade recloser installations to include transfer trip.

Not upgrading the 14 r ecloser installations would result in more service interruptions to customers because faults downstream of the recloser locations must be cleared by the upstream station feeder breaker, which trips the entire feeder.

Alternatives:
Doing nothing is not a viable option since the line recloser installations would not meet current standards and the occurrence of feeder faults downstream of the recloser locations would result in a trip of the entire feeder.

The recommended option is to replace the 14 r ecloser installations to current standards, and upgrade the feeder protection settings and protection coordination between the line reclosers and the station feeder protections. This will results in less service interruptions to customers.

Investment Description:
This investment includes the replacement of reclosers and the installation of transfer trip between each recloser and the downstream DG at all known locations (14 in total). Also, the protection settings and protection coordination of each feeder will be revised so that feeder faults downstream of the recloser locations may be cleared by the line recloser and not by the station feeder breaker; that is, with proper sectionalizing.

Result:
Upgrade line reclosers and associated protections at 14 locations to meet Hydro One standards.

Costs:

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	1.0	-	-	-	-	1.0
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	1.0	-	-	-	-	1.0
Recoverable (C)						
Net Investment Cost (A+C)	1.0	-	-	-	-	1.0

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• In response to an increasing number of customer complaints near DG installations, Hydro One developed engineering standards to upgrade recloser installations to include transfer trip.
Operational Effectiveness	• Improve system reliability as feeder faults downstream of the recloser locations may be cleared by the line recloser and not by the station feeder breaker which trips the entire feeder.
Public Policy Responsiveness	
Financial Performance	

Hydro One Distribution – Investment Summary Document

Development Investment - System Capability Reinforcement

Investment Name: Leamington TS Capital Contribution
In-Service Year: 2017
Primary Outcome: Public Policy Responsiveness

Objective:
To provide capital contributions to Hydro One Transmission for the construction of a new DESN transformer station at Leamington (Leamington TS) and a 230 kV double-circuit line. This will address Transmission assets at end of their expected service life and facilitate improvements to reliability and capacity needs to the Kingsville-Leamington area as well as the surrounding Windsor-Essex area.

Need:
The Kingsville-Leamington area is supplied by the 115 kV – 27.6 kV Kingsville TS. There are several issues at this station: three out of four station transformers are reaching their expected service life, and there are limitations in the thermal capacity and short circuit levels. Hydro One Transmission has identified that the three transformers at the end of their expected service life are in need of replacement. Furthermore, when an outage occurs on one of the four transformers, the station is close to or over its thermal capacity. As both normal load growth and growth from large distribution load customers is expected for the Kingsville-Leamington area, this thermal capacity is expected to be exceeded. Lastly, the short circuit level at Kingsville TS is very close to reaching the allowable limit for distributed generation (DG). This could prevent additional DG from connecting to the distribution system.

Moreover, there are issues with the two 115kV circuits supplying Kingsville TS. The station is currently operating above the load meeting capability of these circuits (120MW) and in the case of a single circuit outage, the other circuit would be overloaded and unable to support adequate delivery voltage to Kingsville TS.

In addtion to the capacity needs in the Kingsville-Leamington area, there is insufficient restoration capability in the 115 kV subsystem to restore the entire load following a 230 kV double-circuit contigency in the Windsor-Essex area.

Not proceeding with this investment would result in multiple, costly projects to address the transmission and distribution issues within the area. This investment provides the most cost effective solution for meeting the needs in the Kingsville-Leamington area and the surrounding Windsor-Essex area.

Alternatives:
Alternatives were developed to address assets reaching their expected service life, loading needs, and reliability issues identified for these areas.

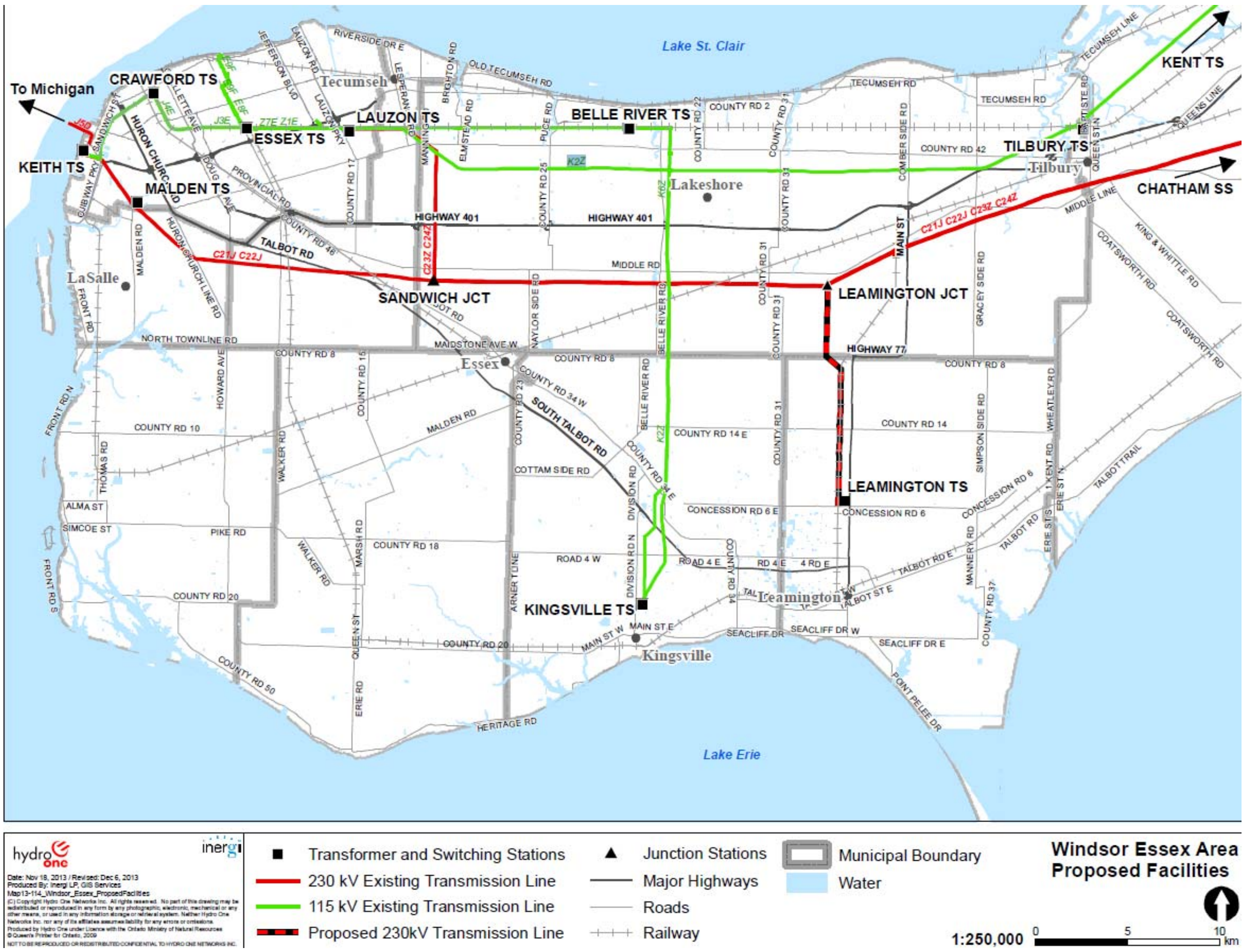
<u>Alternative 1: Do Nothing</u>
This alternative is not recommended because Hydro One Distribution would not be able to meet the supply needs for normal load growth and the additional capacity requirements for large distribution load customers and distributed generation customers.

<u>Alternative 2: Build a new DESN station Leamington TS (Recommended Alternative)</u>
The preferred alternative is to build a new 230 kV – 27.6 kV DESN station at Leamington TS. This alternative offers significant reliability, efficiency and operational improvements. It enables the decommissioning of two of the transformers at Kingsville TS that are reaching the end of their expected service life. It also adresses the concerns with limited thermal capacity and short circuit levels. Furthermore, feeder lengths supplying the Leamington area would be reduced from 15-20 km to 5-10 km, providing improved supply voltages and reduced line losses. This alternative meets all the identified transmission system needs as well as providing additional capacities for both load growth and distributed generation. The total project cost would be approximately $77 million with a Hydro One Distribution capital contribution of $40.4 million. A portion of the contribution will be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area.

<u>Alternative 3: Replace assets reaching end of expected service life, build a new transformer station near Woodslee junction and upgrade the 115 kV connection line supplying Kingsville TS</u>
One alternative is to strengthen the existing 115 kV system and replace the assets reaching their end of expected service life. The existing 115 kV transmission system would be strengthened by building a new transformer station near Woodslee junction and upgrading the 115 kV connection line between the new TS and Kingsville TS. The three transformers at end of expected service life at Kingsville TS would be replaced like-for-like. In addition, two new feeders would be built to address the load growth in Leamington. This alternative is not recommended because the total project cost would be approximately $97 million, which is significantly higher than the recommended alternative.

Investment Description:

The map below depicts the existing and proposed electricity transmission systems in the area:



The preferred solution includes construction of a new transmission station, Leamington TS and approximately 13 km of new 230 kV double-circuit line. The installation of a new 230 kV – 27.6 kV DESN at Leamington improves reliability, provides capacity to accommodate the load growth within the Kingsville-Leamington area, and provides restoration capability for the Windsor-Essex area. With the new DESN in the area, Kingsville TS capacity can be reduced. Only one of the three transformers at the end of their expected service life will be replaced and the other two transformers will be decommissioned.

As a result, Hydro One Distribution will pay capital contributions to Hydro One Transmission for the new Leamington TS and the new 230 kV double-circuit line. A portion of these contributions will be recovered from the embedded local distribution companies and large distribution load customers in the Kingsville-Leamington area. The capital contribution amounts provided in the Costs section below are preliminary and will be determined and finalized in accordance with the Transmission System Code.

Result:

- Increase transformation capacity to meet future load requirements for the Kingsville-Leamington area as per DSC Section 3.3.1
- Improve operational effectiveness by increasing reliability of supply for customers in the Kingsville-Leamington area and the surrounding Windsor-Essex area
- Savings financially through reduction in costs and resources by addressing multiple issues simultaneously

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	-	-	40.4	-	-	40.4
Operations, Maintenance & Administration and Removals (B)	-	-	- -		-	-
Gross Investment Cost (A+B)	-	-	40.4	-	-	40.4
Recoverable (C)	-	-	18.4	-	-	18.4
Net Investment Cost (A+C)	-	-	22.0	-	-	22.0

*Includes Overhead at current rates.

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	100%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Increase in capacity will allow connection of large distribution customers and promote economic development in the area. • Kingsville TS has reached the short-circuit limit for the station and this project will allow more DG customers to connect to the system.
Operational Effectiveness	• Leamington TS will provide 230kV service in the area and shorten feeder lengths which increases efficiency and reliability of the system.
Public Policy Responsiveness	• To meet the requirements of the DSC and Distribution Licence to respond to embedded LDC and large customer requests for increased transformation capacity on the system to accommodate load growth.
Financial Performance	• Cost savings are realized through reduction in costs and resources by addressing multiple issues simultaneously in one project.

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: Operating Compute Refresh
Work Execution Period: June 2018 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
This investment is required to maintain the viability of Operations Information Technology (IT) systems and provide for the dynamic dependencies of applications.

Need:
Common hardware and associated software infrastructure which support diverse Operations systems and applications will be end-of-life and will require lifecycle refresh beginning in 2018. This will maintain the viability of Operations applications such as the Outage Response Management System, the Network Outage Management System, the Network Management System and other mission critical applications.

Alternatives:
Lifecycle management based on i ndustry best practices and vendor support schedules ensure viable operation of these assets. The planned replacement with the appropriate current technology is the only viable option. IT asset lifecycles are typically five years and include capacity growth provisions.

Not proceeding with lifecycle replacements would result in loss of support from the Original Equipment Manufacturer and Vendor, increased maintenance costs, increased probability of system failures and a decreased ability to recover in the event of a failure.

Investment Description:
This investment includes the following assets:

- Common Operations database servers located at both the Ontario Grid Control Center (OGCC) and Backup Control Center (BUCC); and
- Operations workstation consoles located at both the OGCC and BUCC.

Result:
Provides Operations IT infrastructure required to support mission critical Operations systems and applications.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	-	-	-	0.9	1.9	2.8
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	-	-	0.9	1.9	2.8
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	-	-	-	0.9	1.9	2.8

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	
Operational Effectiveness	• Maintain the viability of Operations Information Technology (IT) systems and provide for the dynamic dependencies of applications • Replacement will decrease maintenance costs and probability of system failures and increase the ability to recover in the event of a failure.
Public Policy Responsiveness	
Financial Performance	

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: Network Outage Management System (NOMS) Refresh
Work Execution Period: January 2016 to November 2016
Primary Outcome: Operational Effectiveness

Objective:
This investment is required to refresh the Network Outage Management System (NOMS) which is at its end of life.

Need:
NOMS is an essential tool for planning, scheduling, assessing and executing distribution equipment outages. In 2016, the viability of the tool will be reviewed and investigated for potential options including the implementation of a version upgrade or a total replacement of NOMS. Factors to be considered will be system growth, compatibility with other Operations systems and applications and the availability of new technologies. The current NOMS was put into service in 2010. T he system must be supported by the vendor or Original Equipment Manufacturer (OEM) and upgraded or replaced when this support for the old version is withdrawn.

Alternatives:
Lifecycle asset replacement with the appropriate new technology is the viable option. Typical asset lifecycles in this category are five years and include capacity growth provisions.

Not proceeding with lifecycle replacements would result in loss of support from the OEM and Vendor, increased maintenance costs, increased probability of system failures and a decreased ability to recover in the event of a failure.

Investment Description:
Planned investments include hardware refresh, operating system upgrade and the investigation of the refresh or replacement of the application, considering system growth and new technologies to maintain and improve the efficiency and effectiveness of System Operations. Recommendations and findings will proceed within the investment period including but not limited to: software, system components, interfaces with corporate systems and other hardware as required. This may also include integration with other enterprise systems.

Result:
- Provides the lifecycle sustainment required to support the mission critical NOMS application.
- Provides the opportunity for efficiencies based on pot ential software version application improvements or new emerging technologies.

Costs (M$):

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)		1.4	-	-	-	1.4
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	1.4	-	-	-	1.4
Recoverable (C)	-	-	-	-	-	
Net Investment Cost (A+C)	-	1.4	-	-	-	1.4

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

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Provide flexibility to manage distribution outages in the best interest of Hydro One customers.
Operational Effectiveness	• Maintain and improve the efficiency and effectiveness of NOMS; an essential tool for planning, scheduling, assessing and executing distribution equipment outages.
Public Policy Responsiveness	
Financial Performance	

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: Operating Facilities Refresh
Work Execution Period: June 2017 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
This investment is to maintain the stability of Operations Information Technology (IT) infrastructure at the Ontario Grid Control Centre (OGCC) and Back-Up Control Centre (BUCC), as well as providing flexibility for system modifications, system growth and future upgrades.

Need:
Operations facilities provide for and are considered the foundation for all Operations IT infrastructure. The facilities include:

- physical space (i.e. computer rooms);
- heating, ventilation and air conditioning (HVAC) systems (i.e. computer room air conditioners);
- primary and secondary redundant power supplies (i.e. power distribution units (PDUs); uninterrupted power supplies (UPS); and
- connectivity and networking; etc.

Critical facility assets will require lifecycle replacements beginning in 2017 in order to sustain IT system operability and ensure continued performance at an acceptable level.

Alternatives:
Lifecycle management based on industry best practices and vendor support schedules ensures viable operation of these assets. Replacement with the appropriate and current technology is the viable option. These asset lifecycles are typically ten years and include capacity growth provisions.

Not proceeding with lifecycle replacements may compromise the reliability and availability of the Operations IT infrastructure and the applications and systems they support. This may result in partial or total failure of Operations applications and systems vital for the management, monitoring and operation of the distribution system.

Investment Description:
This investment will sustain the following assets:

- Common Operations system connectivity and networking located at the OGCC
- OGCC UPS batteries, which guard against power interruptions on critical equipment
- OGCC PDU, which provide primary and secondary power distribution to computers and networking equipment located within the computer rooms.

Result:
Sustainment of the facilities support the Operations IT infrastructure operability required to support mission critical Operations systems and applications.

Costs (M$):

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	-	-	0.7	2.1	1.4	4.2
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	-	0.7	2.1	1.4	4.2
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	-	-	0.7	2.1	1.4	4.2

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	
Operational Effectiveness	• Maintain the reliability and stability of Operations Information Technology (IT) infrastructure at the Ontario Grid Control Centre (OGCC) and Back-Up Control Centre (BUCC), as well as providing flexibility for system modifications, system growth and efficiency upgrades.
Public Policy Responsiveness	• Support the Operations IT infrastructure operability required to support mission critical Operations systems and applications to manage, operate and control the distribution system as required.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: New Facility Development
Work Execution Period: June 2014 to December 2018
Primary Outcome: Public Policy Responsiveness

Objective:
This investment is required to establish a new Back-Up Control Centre (BUCC) facility to ensure Network Operations remains compliant with North American Electric Reliability Council (NERC) requirements and reliability and availability targets can be sustained in the event the Ontario Grid Control Centre (OGCC) or its computer systems are rendered inoperable or uninhabitable.

Need:
The BUCC facility consists of the physical building which houses the backup control rooms for the Hydro One transmission and distribution systems and the associated computer rooms. The existing computer rooms (located at Richview TS) are one of the most limiting factors that put the BUCC at risk. They have reached their design limits in terms of physical space, power supply and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of Operating backup facilities has been reduced. Operating has experienced an increase in critical failures, and emergency preparedness considerations have become a significant concern.

Alternatives:
Based on the known deficiencies and associated risk of the existing BUCC facility, the only viable option is to replace it with a new facility. The new BUCC facility will include growth and expansion provisions.

Not proceeding with this investment will result in continued risk to the BUCC functionality of the facility, systems and tools. There is also the possibility of total loss of control of the distribution system in the event the OGCC or its computer systems are rendered unavailable This could affect system reliability and the safety of Hydro One and other Local Distribution Company field staff.

Investment Description:
Benefits resulting from this investment will include:

- Providing a state-of-the-art facility, employing emergency preparedness considerations and industry best practices;
- Providing required capacity with expansion potential for current and future requirements; and
- Improving the reliability of all associated facilities, systems and tools and added efficiency and productivity gains.

Result:
This investment will ensure:
- the BUCC can meet or exceed Network Operating and NERC compliance requirements;
- mitigates existing BUCC risk factors; and
- ensures the backup facilities are sustainable.

Costs (M$):

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	0.5	9.5	5.2	2.9	-	18.6**
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	0.5	9.5	5.2	2.9	-	18.6**
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	0.5	9.5	5.2	2.9	-	18.6**

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.
**Includes expenditures prior to test years.

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	
Operational Effectiveness	• Improving the reliability of all associated facilities, systems and tools and added efficiency and productivity gains.
Public Policy Responsiveness	• Required to establish a new Back-Up Control Centre (BUCC) facility to ensure Network Operations remains compliant with North American Electric Reliability Council (NERC) requirements and reliability and availability targets can be sustained in the event the Ontario Grid Control Centre (OGCC) or its computer systems are rendered inoperable or uninhabitable.
Financial Performance	

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: Storage Area Network (SAN) Upgrade
Work Execution Period: March 2017 to September 2019
Primary Outcome: Operational Effectiveness

Objective:
This investment will provide support and lifecycle management of Information Technology (IT) data storage at the Ontario Grid Control Centre (OGCC) and Back-Up Control Centre (BUCC) facilities.

Need:
The OGCC and BUCC SAN infrastructure will reach end of life in 2017 and will require replacement in order to maintain its viability. The SAN provides a common data storage platform to Operating systems and applications including the Outage Response Management System, the Network Outage Management System, the Network Management System, the Distribution Management System and other mission critical Operations systems and applications required to run an efficient distribution system.

Alternatives:
Lifecycle management based on industry best practices and vendor support schedules ensures viable operation of these assets. Replacement with the appropriate new technology is the only viable option. IT asset lifecycles are typically five years and include capacity growth provisions.

Not proceeding with lifecycle replacements would result in loss of support from the Original Equipment Manufacturer and Vendor, increased maintenance costs, increased probability of system failures and a decreased ability to recover in the event of a failure.

Investment Description:
This investment includes the following assets:
- Operating SAN data storage located at the OGCC and BUCC; and
- Operating data archive storage.

Result:
The SAN and data archive storage will be upgraded with new technology to accommodate current and future capacity requirements suitable for its projected life expectancy of five years.

Costs (M$):

	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	-	-	1.2	1.2	0.9	3.3
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	-	-	1.2	1.2	0.9	3.3
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	-	-	1.2	1.2	0.9	3.3

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	100%	%	%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	
Operational Effectiveness	• Provide support and lifecycle management of Information Technology (IT) data storage at the Ontario Grid Control Centre (OGCC) and Back-Up Control Centre (BUCC) facilities. • Proceeding with lifecycle replacements will result in decreased maintenance costs, decreased probability of system failures and a increased ability to recover in the event of a failure.
Public Policy Responsiveness	
Financial Performance	

Hydro One Distribution – Investment Summary Document

Investment Type: Operations

Investment Name: Outage Response Management System (ORMS) Refresh
Work Execution Period: January 2015 to November 2016
Primary Outcome: Customer Focus

Objective:
Refresh of ORMS which is currently at its end of life.

Need:
ORMS is the tool that analyzes and groups trouble calls, predicts common upstream devices in an abnormal condition, identifies crews, tracks the work flow of the crews and provides the data for performance reporting. It is also a key tool in the interface with Hydro One Distribution's customers. The current ORMS went in service in 2007 and has been in continuous operation 24 x 7 since this time. A lifecycle system refresh is planned to replace hardware and software system components. This is required to maintain and improve the efficiency and effectiveness of distribution system operations.

The proposed work must be completed in order to ensure the ongoing reliability of the critical outage response activities including communications with field crews and customers, and meeting regulatory obligations. A refresh of ORMS current configuration will allow two way communication to the Distribution Management System (DMS) and direct interaction with the Advanced Metering Infrastructure (AMI).

Alternatives:
Lifecycle system replacement with the appropriate new technology is the only viable option.

Failure to proceed with this investment would result in increased risk of application failure. This will Impact the ability of the Distribution Outage Management Center to centrally and effectively manage distribution outages in the safest, most efficient manner. Further, failure of this tool will impact performance of all customer facing systems including the Outage Map which may result in a decrease in customer satisfaction levels.

Investment Description:
Planned investments include hardware refresh, server operating system upgrade and the investigation of the refresh or replacement of the application, considering system growth and new technologies to maintain and improve the efficiency and effectiveness of Distribution System Operations while maintaining Hydro One's core values of safety and reliability. Recommendations and findings will proceed within the investment period including but not limited to:

- Outage Management System (OMS) software;
- system components and hardware as required;

- integration with other enterprise systems including SAP, Supervisory Control and Data Acquisition (SCADA), AMI, DMS, Geographic Information System and mobile Information Technology (IT).

Integrating systems used to dispatch crews for both regular work and trouble call work will increase the efficiency of Dispatchers by allowing them to recognize the possible location of the cause of an unplanned outage, identify and dispatch the closest crew and shorten restoration times. Other real-time and historical data will be used for business reporting and analytics to help Hydro One to identify and resolve power quality problems, catch theft of power, monitor feeder performance and handle outage inquiries.

Result:
- Improve efficiencies in managing, tracking crews and communicating with customers for planned and unplanned outages;
- Enable ORMS to receive SCADA, AMI, SAP, DMS information to improve outage response times;
- Improve customer service with increased system performance, shorter response times and more effective customer communications using multiple communication paths and mediums (e.g. text, SMS, E-mail) during outages;
- Improve analytics; and
- Provide the opportunity to take advantage of new OMS innovations available with the advent of the smart grid.

Costs:

	2015	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	8.0	8.0	-	-	-	19.0**
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	8.0	8.0	-	-	-	19.0**
Recoverable (C)	-	-	-	-	-	
Net Investment Cost (A+C)	8.0	8.0	-	-	-	19.0**

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.
**Includes expenditures prior to test years.

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Real-time and historical data will be used for business reporting and analytics to help Hydro One to identify and resolve power quality problems, catch theft of power, monitor feeder performance and handle outage inquiries. • Improve customer service with increased system performance, shorter outage response times and more effective customer communications using multiple communication paths and mediums (e.g. text, SMS, E-mail) during outages.
Operational Effectiveness	• Maintain and improve the efficiency and effectiveness of distribution system operations and ensure the ongoing reliability of the critical outage response activities including communications with field crews and customers, and meeting regulatory obligations.
Public Policy Responsiveness	
Financial Performance	• Integrating systems used to dispatch crews for both regular work and trouble call work will increase the efficiency of Dispatchers by allowing them to recognize the possible location of the cause of an unplanned outage, identify and dispatch the closest crew and shorten restoration times.

Hydro One Distribution – Investment Summary Document

Common Corporate Costs – Facilities & Real Estate

Investment Name: Real Estate Head Office and GTA Facilities Capital for 2015
Work Execution Period: January 2015 to December 2015
Primary Outcome: Operational Effectiveness

Objective:
Complete required head office facility improvements.

Need:
The Facilities Capital Work Program is responsible to ensure program delivery in terms of capital improvements and providing for the company's accommodation needs. The funding requirements in 2015 mainly reflect investments to replace facilities that are at end-of-life and to meet the anticipated work space accommodation needs.

Capital investment of $13.1 million is required in 2015 to provide for head office accommodation improvement work that initially began in late 2011 and is expected to continue in the bridge year 2014 and test year 2015.

Effective February 1, 2010 Hydro One Networks has secured an eleven year lease for 483 Bay Street, to serve its ongoing head office requirements. Within the completed lease renewal, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems and infrastructure, and provide allowances for tenant improvements.

In 2015 the gross leasehold improvements and the furniture systems funding requirements are estimated to be $9.1 million and $4.0 million respectively. The leasehold improvements are necessary as major head office building infrastructure elements are now at end of life and require replacement. Similarly, the present furniture systems were acquired from the previous tenant, refurbished and are also now considered to be at end of life. The planned tenant improvements are part of the negotiated lease agreement. These investments are required to complete the improvement work that began in late 2011. They help avoid inefficiencies caused by aged facilities and improve staff health and safety protections and performance.

Investment Description:
Capital investment of $13.1 million is required in year 2015 to provide for head office accommodation improvements to support day-to-day business and operations activities.

Alternatives:
Moving to an alternate location is an alternative, but the cost of doing so would outweigh the investment described here. Also, Hydro One is contractually committed to lease the current space for eleven years commencing in February 2010.

Result:
Completed necessary improvements to head office space to avoid inefficiencies and health and safety hazards associated with deteriorating workplace infrastructure.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	13.1	0	0	0	0	13.1
Operations, Maintenance & Administration and Removals (B)						
Gross Investment Cost (A+B)	13.1	0	0	0	0	13.1
Recoverable (C)						
Net Investment Cost (A+C)	13.1	0	0	0	0	13.1

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	%	%	100%

Hydro One Networks – Investment Summary Document
Common Corporate Costs – Facilities & Real Estate

Investment Name: Real Estate Field Facilities Capital
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
The Field Facilities Capital work program addresses portfolio accommodation needs in terms of facility improvements, building additions and new facilities, as determined by Hydro One Networks operational requirements. This program ensures that critical structural improvements and other improvements to building integrity are made to administration and service facilities which minimize building and site-related risks to operations; serve operational requirements; and promote efficiencies through the optimal maintenance and operation of the facilities in the longer term.

Need:
The capital investment is required for field facilities in order to continue to provide adequate and appropriate workspace accommodation for core work programs and changing requirements of the lines of business. The investment need is driven by the following key factors:
- aging facilities that are at or near the end of life;
- compliance with current code and regulatory requirements;
- expanding work programs;
- new accommodation needs;
- evolving work practices;
- improvements in health and safety requirements;
- improvements in security requirements;
- barrier-free access (Accessibility for Ontarians with Disabilities Act); and
- sustainable development.

Capital investment in the aging facilities asset base is required to meet the accommodation needs of the business units. Approximately 40% of administration and service centre facilities infrastructure is estimated to be more than 40 years old. The facilities are largely undersized, ill-configured, underperforming to current operational requirements resulting in increasing operating costs for maintenance and repair and presenting an ongoing inefficiency to facility and business operations.

The Field Facilities Capital Work Program focuses on undertaking facility work, which entails improvements, additions or new facilities, on a priority basis in a cost effective manner that minimizes risk to business operations and fully delivers the prescribed various work programs in a safe and efficient manner. The work is conducted on a project basis.

Investment Description:
Key program work activities include:

- addressing accommodation requirements in terms of new buildings, buildings additions and major facility renovations; and
- replacing major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements and building systems.

A capital investment of $26.5M is required for year 2015. $31.5 million is required annually for 2016 and 2017, and $36.5M is required annually for 2018 and 2019. These amounts are needed to fund new accommodation solutions, address needs for new buildings, buildings additions, and facilities improvements, as required by the company's work programs.

The locations targeted for investments starting in 2014 – 2019 are set out in Table 1. Projects can be multi-year projects, and work is contingent on obtaining the requisite municipal planning approvals. The total costs of the Field Facilities Capital work program in 2015 - 2019 is provided in the costs section below and includes these projects.

Table 1: Planned Investment Locations

Project Name	Planned Investment	Start Year
London, 320 South Edgeware (New Garage)	Building and site improvements to acquired property to align with current and planned operations.	2014
London, 425 South Edgeware (New Operation Centre)	Building and site improvements to acquired property to replace existing disparate and undersized facilities at Buchanan TS.	2014
Belleville, 21 Enterprise (New Operation Centre)	Building and site improvements to acquired property to facilitate the consolidation of three facilities that are undersized and ill configured to meet business operations, i.e. Zone 3B FBC (Belleville TS), Travelling Line Crew (120 Adam Street, Belleville) and Bellville Garage.	2014
Alliston Operation Centre (Building & Site Improvements)	Tenant improvements (building and site) to existing leased facility to address health and safety issues and address gaps to operational requirements.	2014
Kleinburg Lines Training (Classrooms)	Additional classrooms to fully address training requirements and replace underperforming office trailers currently serving as classrooms.	2014
Orleans Operation Centre (New Phase 2)	Permanent operations centre for recently created Orleans customer area, which is being serviced by an interim and partially constructed	2015

	facility (Phase 1).	
Project Name	**Planned Investment**	**Start Year**
Bolton, Operation Centre (New)	Permanent operations centre for the recently created Bolton customer area, which is being serviced by an interim trailer facility.	2014
Moosonee Service Centre (Acquisition / New)	Acquisition of current leased facility, which is being divested by owner (Government of Canada).	2014
Stayner Operation Centre (New)	New facility to replace existing leased facility (Stayner Service Centre) that is undersized, ill-configured and in poor condition and facilitate consolidation of staff (Stayner Service Centre and Barrie Operation Centre).	2017
Dryden Operation Centre (New)	New facility to replace existing undersized and end of life facility, i.e. Dryden Service Centre.	2014
Dryden Garage (New)	New facility to replace existing undersized, ill equipped and end of life facility, i.e. Dryden Garage.	2015
Dryden Hanger (New)	Replace leased facility that is inadequate (undersized and shared with third parties) for operations.	2017
Owen Sound Operation Centre	New facility to replace existing disparate, undersized and end of life facilities, i.e. Rockford Service Centre and Owen Sound Service Centre.	2014
Arnprior Operation Centre	New facility to replace existing disparate and undersized facilities, i.e. Arnprior Work Centre, former Arnprior Service Centre (material & equipment storage) and Arnprior Forestry Work Centre.	2017
Arnprior Garage	New facility to replace undersized facility, i.e. Arnprior Garage (located within former Arnprior Service Centre).	2017
Thunder Bay Hanger	Replace leased facility that is inadequate (undersized and shared with third parties) for operations and must be vacated by Q1 2015.	2014
Thunder Bay Garage	Tenant improvements to existing leased Thunder Bay Garage to replace end-of-life elements and gaps to operational requirements.	2014
Guelph Operation Centre (New Phase 1)	Interim facility to facilitate GATR project at Guelph Cedar TS in 2014, which is being serviced by interim and partially constructed facility (Phase 1).	2014
Guelph Operation Centre (New Phase 2)	Permanent facility (Phase 2) to interim facility.	2018
Timmins Operation Centre (New)	New facility to replace existing disparate, undersized and end-of-life facilities, i.e. Timmins Business Centre and Timmins TS Maintenance Centre.	2019
Bracebridge Operation Centre (New)	New facility to replace existing disparate leased facilities that are undersized and ill-configured (Bracebridge/Muskoka Service Centre and Bracebridge Forestry Work Centre.	2019
Sudbury Operation Centre (New or Addition/Renovation)	New or renovated and expanded facility to address crowding, safety issues and gaps to operational requirements.	2015

Result:

- Secured necessary accommodation space in the field in line with work programs requirements.
- Improved Administration and Service Centre facilities through replacement of roof structures, windows, HVAC systems and other structural elements.

Alternatives:

For each site the range of alternatives varies with opportunity; and a cost-benefit analysis is undertaken for the alternatives. The opportunity to renovate existing sites must also consider the need to maintain operations, which may necessitate an interim site with the associated cost and disruption.

Many of the existing facilities are not suitable candidates for renovation or additions because:

- they are interim facilities;
- they reside on undersized sites with no opportunity for expansion;
- it is impractical to renovate or expand them because condition or configuration of existing improvements;
- they are incompatible to surrounding land uses that have changed with time;
- they are impacted by environmental conditions that affect cost and value of the investment;
- they are otherwise constrained by regulation from achieving objectives from an operational or cost perspective; or
- there is no management control to complete changes because the facility is leased.

As an example from the planned investments in Table 1, the Dryden OC is impacted by on-site contamination extending under the building; situated on an undersized site; supplied by an on-site well that is not potable; and requires an interim facility to facilitate renovations and expansion.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	26.5	31.5	31.5	36.5	36.5	162.5
Operations, Maintenance & Administration and Removals (B)						
Gross Investment Cost (A+B)	26.5	31.5	31.5	36.5	36.5	162.5
Recoverable (C)						
Net Investment Cost (A+C)	26.5	31.5	31.5	36.5	36.5	162.5

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

Investment Category:

System Access	System Renewal	System Service	General Plant
%	%	%	100%

Hydro One Distribution – Investment Summary Document

Common Corporate Costs and Other

Investment Name: Security Infrastructure
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
The objective of this program is to determine and provide an effective solution to the rise of copper theft within Hydro One distribution stations.

Need:
The Distribution Station Security Upgrade Program addresses the need to implement theft deterrents due to increasing copper theft occurrences within distribution stations. C opper in station ground grids, fence ground grids, ground connections and neutral connections for electrical equipment are often targeted for theft in Hydro One distribution stations. T hese incidents can result in physical injury, including death. Most recently, there was an incident resulting in serious injuries at Port Perry Distribution Station in October 2013. The removal of ground and neutral copper connections compromises the electrical integrity of the grounding system. This can pose safety hazards to Hydro One employees and the general public.

Thieves have gained access into stations by cutting through chain-link fence fabric or breaking lock mechanisms. This investment program will address copper theft through the installation of new products as a pilot to reduce copper theft occurrences and improve health and safety protections benefiting Hydro One employees and the general public. This will also help avoid replacement costs associated with copper theft, which are detailed in Table 1 below.

Table 1 below shows the number of recorded intrusions, copper theft occurrences and dollars spent on addressing stolen copper from 2010 to 2013:

Table 1: Number of Recorded Copper Theft Occurrences & Associated Dollars Spent

Year	2010	2011	2012	2013
Number of break & enter occurrences	33	40	50	24
Number of copper theft occurrences	28	37	41	18
Dollars spent to addressing stolen copper	$112,024	$187,901	$216,597	$114,954

Alternatives:

No Funding Alternative

If no funding is provided to allow for security upgrades in distribution stations, then copper and neutral grounds will continue to be stolen. Hydro One maintenance staff will continue to replace the stolen grounds under Corrective Maintenance programs, and thieves will continue to return to the same stations to steal the ground and neutral conductors once they are replaced, jeopardizing the health and safety of those involved.

Preferred Alternative

The preferred alternative is to install and test new products under as a pilot initiative to deter thieves from stealing copper and neutral conductors. If the products are successful at deterring theft and "break-ins", and determined to be cost effective, then they will be installed at other stations that are also prone to theft. If the products are evaluated and found to be not successful and economical, then other products will be tested at stations as a pilot initiative.

Investment Description:

Yearly candidates for distribution station security upgrades include the stations in the following table. These stations have historically been frequent targets of copper theft. This candidate list will be updated in subsequent years between 2015 and 2019 based on copper theft occurrences and theft mitigation strategies.

2015	2016	2017	2018	2019
Mountain View DS	Beachwood DS	Seagrave DS	Glenarm DS	TBD
West Lake DS	North Augusta DS	Greenbank DS	Holland DS	TBD
Addison DS	Maitland DS	Oakwood DS	Wesley DS	TBD

Result:

- A solution to deter copper theft within Hydro One distribution stations will be installed and implemented.
- The number of copper theft occurrences is expected to be reduced.
- The electrical integrity of station and fence grounding in Hydro One distribution stations will be preserved.
- General public and Hydro One employee safety at distribution station perimeters and within stations will be maintained.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	1.0	1.0	1.1	1.1	1.1	5.3
Operations, Maintenance & Administration and Removals (B)	-	-	-	-	-	-
Gross Investment Cost (A+B)	1.0	1.0	1.1	1.1	1.1	5.3
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	1.0	1.0	1.1	1.1	1.1	5.3

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

Investment Category:

System Access	**System Renewal**	**System Service**	**General Plant**
%	25%	%	75%

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment
Historical (2010, 2011, 2012, 2013), Bridge (2014) & Test (2015 to 2019) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance
		(a)	(b)	(c)	(d)	(e)	(f)
Historic							
1	2010	7,127.2	549.0	(19.9)	(8.9)	(8.4)	7,639.1
2	2011	7,639.1	528.7	(38.0)	(10.8)	1.6	8,120.6
3	2012	8,120.6	554.2	(26.9)	(10.3)	(1.3)	8,636.3
4	2013	8,636.3	729.3	(93.8)	(15.6)	0.0	9,256.1
Bridge							
5	2014	9,256.1	637.6	(28.4)		0.0	9,865.4
Test							
6	2015	9,865.4	656.6	(62.1)		0.0	10,459.9
7	2016	10,459.9	621.8	(60.1)		0.0	11,021.6
8	2017	11,021.6	696.0	(40.8)		0.0	11,676.8
9	2018	11,676.8	681.4	(91.6)		0.0	12,266.6
10	2019	12,266.6	660.9	(140.7)		0.0	12,786.8

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2010, 2011, 2012, 2013), Bridge (2014) & Test (2015 to 2019) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Provision	Retirements	Sales	Transfers In/Out	Closing Balance
		(a)	(b)	(c)	(d)	(e)	(f)
Historic							
1	2010	2,616.2	232.7	(19.9)	(8.0)	(0.0)	2,821.1
2	2011	2,821.1	250.4	(38.0)	(9.6)	0.0	3,024.0
3	2012	3,024.0	269.3	(26.9)	(9.1)	(3.4)	3,253.9
4	2013	3,253.9	277.7	(93.8)	(14.3)	0.0	3,423.5
Bridge							
5	2014	3,423.5	291.2	(28.4)		0.0	3,686.3
Test							
6	2015	3,686.3	302.9	(62.1)		0.0	3,927.1
7	2016	3,927.1	313.9	(60.1)		0.0	4,180.9
8	2017	4,180.9	326.6	(40.8)		0.0	4,466.7
9	2018	4,466.7	337.7	(91.6)		0.0	4,712.7
10	2019	4,712.7	347.0	(140.7)		0.0	4,919.1

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Continuity of Property, Plant and Equipment - Construction Work in Progress
Historical (2010, 2011, 2012, 2013), Bridge (2014) & Test (2015 to 2019) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Capital Expenditures	Transfers To Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historic					
1	2010	230.6	529.0	(485.8)	273.8
2	2011	273.8	540.1	(477.9)	336.1
3	2012	336.1	582.3	(497.7)	420.7
4	2013	420.7	632.7	(729.3)	324.1
Bridge					
5	2014	324.1	624.5	(637.6)	310.9
Test					
6	2015	310.9	648.9	(656.6)	303.1
7	2016	303.1	654.7	(621.8)	336.1
8	2017	336.1	661.4	(696.0)	301.5
9	2018	301.5	655.1	(681.4)	275.1
10	2019	275.1	669.1	(660.9)	283.4

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Statement of Working Capital
Annual Average
Test Years (2015 to 2019)
($ Millions)

Line No.	Particulars	2015 (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)
1	Cash Working Capital	$ 249.9	$ 253.6	257.3	$ 257.2	257.7
2	Materials and Supplies	6.5	6.6	6.8	6.9	7.0
3	Total	$ 256.4	$ 260.3	264.0	$ 264.1	264.7