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BY COURIER

December 21, 2017

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

Dear Ms. Walli,

RE: EB-2017-0049 – Update to Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application")

Since filing the Application on March 31, 2017, Hydro One has (a) completed another investment planning cycle resulting in an updated distribution business plan approved by its Board of Directors on December 8, 2017; (b) received a decision in its 2017-2018 transmission revenue requirement application (EB-2016-0160) ("2017-2018 Tx Decision"); and (c) received an updated valuation for its other post-employment benefits ("OPEB") plan. On November 23, 2018, the Ontario Energy Board issued cost of capital parameters and inflation factor for 2018.

As Procedural Order No. 2 established January 19, 2018 as the start date for the interrogatory phase of this proceeding, to facilitate the timely litigation of its Application, Hydro One has attempted to capture in a new Exhibit Q the relevant impacts of these developments on this Application. Hydro One has also updated Exhibit E2, Tab 1, Schedule 1 (Reveue Requirement Workform).

Exhibit Q describes the impact to proposed revenue requirement of the following developments:

- the 2018 cost of capital parameters issued by the OEB which increased the return on equity rate from 8.78% to 9.0% and the short-term debt rate from 1.76% to 2.29%;
- Hydro One's 2017 actual debt issuances and forecasted long-term debt rates for 2018;
- an updated Capital Factor to reflect the new revenue requirement and the OEB's new, lower inflation factor (reduced from 1.9% to 1.2%);

- a total reduction to the 2018 OM&A forecast of approximately $5.1 million due to lower costs for executive compensation ($3.2 million) and OPEB ($1.9 million);
- a reduction in the capital forecast due to increased productivity targets, project-level changes in General Plant investments, and lower capitalized pension and OPEB costs and associated depreciation expense; and
- updated depreciation and amortization rates for General Plant (common corporate) assets that align with the OEB's 2017-2018 Tx Decision.

Additionally, Exhibit Q describes:

- strategic changes to Hydro One's vegetation management program;
- a reallocation of certain distribution station costs between rate classes, specifically impacting customers in the new rate classes for the Acquired Utilities; and
- corrected historical values for Hydro One's actual return on equity.

Cumulatively, the adjustments result in a 2018 total revenue requirement of $1,517.1 million, which is 3.5% higher than the 2017 OEB-approved revenue requirement, or a 2018 rates revenue requirement (net of deferral and variance account dispositions) of $1,469.7 million, which is 3.1% higher than the 2017 OEB-approved amount. After adjusting for a reduced load forecast (3.0%), the resulting average impact on distribution rates is an increase of 6.1% in 2018 and an annual average increase of 3.4% over the 2018-2022 period.

Please note that Exhibit Q's presentation of the reallocation of costs between rate classes does not use the updated revenue requirement figure. Because of the significant effort and time required, Hydro One intends to recalculate rates after all adjustments to its proposed revenue requirements are final.

Hydro One intends to post electronic copies of Exhibit Q, its attachments, and the updated Exhibit E2, Tab 1, Schedule 1 (Reveue Requirement Workform) on its website for public access and two paper copies will be sent to the OEB office shortly.

Hydro One's points of contact for service of documents associated with the Application remain as listed in Exhibit A, Tab 2 Schedule 1.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea
Encls.
cc. EB-2017-0049 parties (electronic)

DECEMBER 2017 UPDATE

INTRODUCTION

This Exhibit describes the impact of a number of developments since Hydro One filed this Application on March 31, 2017 and updated on June 7, 2017. These developments include modifications to Hydro One's Distribution Business Plan, which was approved on December 8, 2017 and provided as Attachment 1 to this Exhibit.

Procedural Order No. 2 established January 19, 2018 as the start date for the interrogatory phase of this proceeding. In light of this timing, Hydro One has attempted to capture in this Exhibit the relevant impacts of these developments on this Application. A comprehensive re-filing of the Application is not proposed as this would involve an inordinate work effort unnecessarily causing delay to this proceeding.

Section 1 of this Exhibit describes the impact of the following items to the proposed revenue requirement:

1. the 2018 cost of capital parameters issued by the OEB on November 23, 2017, which increased the return on equity rate from 8.78% to 9.0% and the short-term debt rate from 1.76% to 2.29%;
2. Hydro One's 2017 actual debt issuances and forecasted long-term debt rates for 2018;
3. an updated Capital Factor to reflect the new revenue requirement and the OEB's new, lower inflation factor (reduced from 1.9% to 1.2%) which was also issued on November 23, 2017;
4. a total reduction to the 2018 OM&A forecast of approximately $5.1 million due to lower costs for executive compensation ($3.2 million) and other post-employment benefits ($1.9 million);

5. a reduction in the capital forecast due to increased productivity targets and changes in General Plant investments combined with reduced capital spending due to pension and OPEB costs ($106.3 million over five years) and associated depreciation expense; and
6. an update to depreciation and amortization rates for General Plant (common) assets to align with the OEB's decision dated September 28, 2017 in Hydro One's 2017-2018 transmission application (EB-2016-0160) as it pertained to those common asset costs ("**2017-2018 Tx Decision**").

Section 2 of this Exhibit provides:

7. an update on strategic changes to Hydro One's vegetation management program;
8. a reallocation of certain distribution station costs between rate classes, specifically impacting customers in the new rate classes for the Acquired Utilities; and
9. a letter sent to the OEB in July 2017 correcting historical values for Hydro One's actual return on equity.

Procedural Order No. 2 established January 19, 2018 as the start date for the interrogatory phase of this proceeding. Hydro One has attempted to capture in this Exhibit the relevant impacts of these developments on this Application, as a comprehensive update would involve significant effort and would likely delay the proceeding further.

1. IMPACT ON REVENUE REQUIREMENT

The cumulative impact of these developments on revenue requirement is detailed in this Section. Table 1 provides the incremental change to each line item in the 2018 revenue requirement calculation, as compared to (a) the last 2017 OEB-approved figures and the (b) the June 2017 update to this Application.

Table 1: 2017 OEB Approved and 2018 Proposed Revenue Requirement ($ Million)

Components	2017[1] Approved	2018 As of June	2018 As of December	2018 June vs. December	2018 December vs. 2017	2018 December vs. 2017
OM&A	593.0	584.8	579.6	(5.1)	(13.3)	-0.9%
Depreciation and Amortization	390.2	392.6	397.1	4.5	6.9	0.5%
Income Taxes	48.7	61.5	65.4	3.9	16.7	1.2%
Return on Capital	435.8	461.1	475.0	14.0	39.3	2.7%
Total Revenue Requirement	**1,467.6**	**1,499.9**	**1,517.1**	**17.2**	**49.5**	**3.5%**
Deduct External Revenues and Other	(52.7)	(53.6)	(53.6)	0.0	(0.9)	-0.1%
Rates Revenue Requirement	**1,414.9**	**1,446.3**	**1463.5**	**17.2**	**48.6**	**3.4%**
Regulatory Deferral and Variance Accounts Disposition	11.1	6.2	6.2	0.0	(4.9)	-0.3%
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,452.4**	**1,469.7**	**17.2**	**43.7**	**3.1%**

Exhibit Reference: E1-1-1

Note 1: The 2017 revenue requirement is from the OEB approved Hydro One Distribution's 2015 to 2017 rate application in EB-2013-0416

The updated December 2018 revenue requirement reflects an increase of 3.1% over 2017 OEB-approved levels as presented in the table above. After adjustment for a reduced load forecast (3.0%), the resulting average impact on distribution rates is an increase of 6.1% in 2018, and an average of 3.4% per annum over the Term. In comparison, the average impact on distribution rates in the original Application filed March 31, 2017 was 6.5% in 2018 and 3.7% per annum over the Term. In the June 2017 update, the average impact on distribution rates in 2018 was 4.9%, an average of 3.5% per annum over the Term.

It is anticipated that any changes to the proposed revenue requirement would have a corresponding impact on the proposed base distribution rates and associated bill impacts.

In other words, the 1.2% increase in the revenue requirement since the blue page update would result in an additional 1.2% increase to the proposed base distribution rates and associated impacts relative to approved 2017 rates. Given the relatively modest change to the proposed revenue requirement, Hydro One has not updated its bill impact calculations as the differences are not expected to be materially different.

Table 2 expresses the revised revenue requirement calculation over the 2018-2022 period based on the previously proposed Custom Revenue Cap Index as discussed in Exhibit A, Tab 3, Schedule 2.

Table 2: Summary of Revenue Requirement Components ($ Millions)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,666.4	8,026.9	8,430.5	8,960.1	9,326.5
2	Return on Debt	E1-1-1	199.0	208.4	218.9	232.5	242.0
3	Return on Equity	E1-1-1	276.0	289.0	303.5	322.4	335.6
4	Depreciation	C1-6-2	397.1	418.2	433.1	452.1	465.9
5	Income Taxes	C1-7-2	65.4	69.0	71.5	78.9	79.5
6	Capital Related Revenue Requirement		937.5	984.5	1,026.9	1,085.8	1,122.9
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.9)	(5.1)
8	**Total Capital Related Revenue Requirement**		**937.5**	**980.1**	**1,022.3**	**1,080.9**	**1,117.9**
9	OM&A	C1-1-1	579.6	584.0	588.3	592.8	608.0
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,517.1**	**1,564.1**	**1,610.7**	**1,684.4**	**1,725.9**
12	Increase in Capital Related Revenue Requirement			42.6	42.2	58.6	36.9
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.81%	2.70%	3.64%	2.19%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.34%**	**2.23%**	**3.16%**	**1.71%**

Exhibit Reference: A-3-2

The financially impactful items are described separately below.

1.1 A REDUCTION TO THE 2018 OM&A FORECAST

As indicated in Hydro One's Additional Compensation Evidence, filed with the OEB on December 12, 2017, Hydro One proposes to reduce rate-recoverable executive compensation expenses by $3.2 million, as they relate to 'transformation' costs (as defined in the 2017-2018 Tx Decision). Hydro One has reflected this reduction in the 2018 OM&A and the corresponding revenue requirement.

On December 12, 2017 Hydro One received a new actuarial valuation for its 2018-2023 post-employment benefits (OPEB) plan. Based on the updated valuation, Hydro One has reduced the amount of OPEB expense forecast in 2018 OM&A by $1.9 million. Hydro One has also reduced the amount of OPEB expense included in its capital forecast for the period 2018-2022 as indicated below in Section 1.2.

The reductions for transformation costs and OPEB OM&A expenses are reflected in Table 3, reducing 2018 OM&A expenses, and revenue requirement by a total of $5.1 million.

Table 3: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	334.5	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	13.2	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	33.4	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	132.6	111.6	131.6
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	54.4	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	4.7	5.0	4.9
Total (June Update)	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**572.8**	**593.0**	**584.8**

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Transformation Costs Reduction								(3.2)
OPEB OM&A Reduction								(1.9)
Total (December Update)	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**572.8**	**593.0**	**579.6**

Exhibit Reference: C1-1-1

These cuts are in addition to the reduction of $7.1 million in pension expenses that Hydro One included in its Application update in June 2017 which reduced its OM&A expenses. Combined, the reductions for transformational costs ($3.2 million), pension costs ($7.1 million) and OPEB costs ($1.9 million) amount to a total reduction of $12.2 million to the compensation expenses originally proposed in this Application, ultimately reducing the OM&A expenses for 2018 and subsequently for 2019-2022.

As a result of these reductions, the OM&A requested for recovery in the test year is 2.3% lower than the 2017 OEB-approved amount. Compared to the 2017 forecast, it is an increase of 1.2%.

1.2 A REDUCTION IN THE CAPITAL FORECAST; UPDATED RATE BASE AND IN-SERVICE ADDITIONS FORECASTS

Since the Application was filed on March 31, 2017 and subsequently updated on June 7, 2017, Hydro One has now completed an annual investment planning cycle with its new management team. The outcome of this process has caused Hydro One to make adjustments to General Plant projects, productivity targets, and lower capital expenditures due to reduced pension and OPEB costs. The revised capital forecast over the five year period has been reduced by a total of $106.3 million. Revised annual capital forecasts for each year is reflected in Table 4, together with the revised 2018 OM&A forecasts escalated by the OEB's approved 2018 inflation factor of 1.2%, (less the stretch factor of 0.45%) over the 2019-2022 period.

Table 4: Summary of Distribution Capital and OM&A Expenditures ($ Millions)

	Historical (previous plan and actual)											Forecast (planned)				
	2013 [1]	2014 [1]	2015			2016			2017 Bridge [2]			2018	2019	2020	2021	2022
	Plan	Plan	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Test	Test	Test	Test	Test
CATEGORY	$M	$M	$M		%	$M		%	$M		%	$M	$M	$M	$M	$M
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3	143.1	166.7	116.2	103.7	105.9
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)	628.1	736.4	699.3	711.0	796.5
System OM&A [3]	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)	579.6	584.0	588.3	603.5	608.0

1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.
2) Bridge year 2017 is a forecast as of end of 2016
3) System OM&A values include all Operations, Maintenance and Administration expenses.

Exhibit Reference: B1-1-1

The decreased capital forecast is the result of (a) reduced pension and OPEB expenses and (b) changes to General Plant (i.e Common Corporate Capital) investments driven by modified productivity targets and project-level changes, as indicated in Table 5 below.

Table 5: Changes to Capital Forecast

$Millions	2018	2019	2020	2021	2022
Original Forecast	**633.9**	**756.8**	**719.0**	**740.7**	**827.2**
Pension Capital Reduction	(8.2)	(8.9)	(10.6)	(11.9)	(12.5)
OPEB Capital Reduction	(1.8)	(1.9)	(2.0)	(2.1)	(2.0)
Common Corporate Capital Adjustments / Productivity	4.2	(9.5)	(7.0)	(15.7)	(16.2)
Total Capital December Update	**628.1**	**736.4**	**699.3**	**711.0**	**796.5**

Since Hydro One filed its Application in March 2017, in addition to the OPEB and pension forecast changes reflected in Table 5, the Common Corporate Capital forecasts have changed as follows.

- In 2018, the forecast increased by $4.2 million mostly due to scope refinement for the Integrated Operating Centre investment (ISD GP18). The increase was partially offset by lower spending on transportation and work equipment (ISD GP01) due to higher productivity savings through the telematics program, and lower spending on the work management and mobility investment (ISD GP10).
- In 2019, the forecast is $9.5 million lower due to higher productivity targets for the transportation and work equipment investment (ISD GP01) based on the telematics program and lower spending on the Integrated Operating Centre (ISD GP18) as a result of schedule adjustments and scope refinement. The reduction is partially offset by an acceleration of human resource and pay-related technology investments (ISD GP13) to align with Hydro One's outsourcing agreement.
- In 2020, the forecast is $7.0 million lower reflecting higher productivity targets for the transportation and work equipment investment (ISD GP01) based on the telematics program.
- In 2021, the forecast is $15.7 million lower primarily due to higher productivity targets for the transportation and work equipment investments (ISD GP01) (based on the telematics program), lower spending on work management and mobility (ISD GP10) and lower spending on real estate facilities capital investments (ISD GP02).
- In 2022, the forecast is lower by $16.2 million due to higher productivity targets for transportation and work equipment investment (ISD GP01) (based on the telematics program) and lower spending on the real estate facilities capital (ISD GP02).

Table 6 provides the revised in-service additions forecast based on the capital forecast described above. An updated rate base forecast is provided in Table 7 below.

Table 6: In-Service Capital Additions 2018-2022 ($M)

	Forecast				
	2018	**2019**	**2020**	**2021**	**2022**
Sustaining	292.5	335.6	361.5	384.2	427.3
Development	194.4	268.9	218.9	219.2	221.0
Operations	12.4	6.6	68.6	0.6	19.2
Customer Service	30.2	0.2	0.2	0.2	0.2
Common & Other	105.6	143.9	99.3	100.3	116.7
Total	**635.1**	**755.2**	**748.5**	**704.6**	**784.4**

Exhibit Reference: D1-1-2

Table 7: Distribution Rate Base ($ Millions)

Description	**Test**				
	2018	**2019**	**2020**	**2021**	**2022**
Mid-Year Gross Plant	11,905.1	12,484.4	13,143.1	13,988.0	14,666.8
Mid-Year Accumulated Depreciation	(4,564.1)	(4,798.7)	(5,067.4)	(5,412.3)	(5,741.1)
Mid-Year Net Plant	**7,341.1**	**7,685.7**	**8,075.7**	**8,575.8**	**8,925.7**
Cash Working Capital	321.2	335.7	348.3	378.5	395.3
Materials and Supplies Inventory	4.1	5.5	6.5	5.9	5.5
Distribution Rate Base	**7,666.4**	**8,026.9**	**8,430.5**	**8,960.1**	**9,326.5**

Exhibit Reference: D1-1-1

1.3 COST OF CAPITAL

As indicated in Exhibit D1, Tab 2, Exhibit 1, Hydro One anticipated updating the revenue requirement when the Board released its 2018 cost of capital parameters, reflecting: (a) the OEB-approved 2018 return on equity and short-term debt rates; and (b) a long-term debt rate based on Hydro One's actual 2017 debt issuances to-date and the September 2017 Consensus Forecast. Updates for these changes are summarized in Table 8 below, and applied to the updated Distribution Rate Base amounts described in Table 7 above.

Table 8: 2018 Cost of Capital

Amount of Deemed	($M)	%	Cost Rate (%)	Return ($M)
Long-term debt	3,768.1	49.2	4.47	168.5
Short-term debt	306.7	4.0	2.29	7.0
Deemed Long-Term debt	525.1	6.8	4.47	23.5
Common equity	3,066.6	40.0	9.00	276.0
Total	7,666.4	100.0	6.20	475.0

Exhibit Reference: D1-2-1

1.4 UPDATE TO DEPRECIATION AND AMORTIZATION EXPENSES

As indicated in Exhibit C1, Tab 6, Schedule 1, depreciation rates on common assets are updated in Hydro One's financial systems to reflect the most recent OEB approved depreciation rates. 2018 is a common test year for this Application and Hydro One's 2017-2018 transmission rate application (EB-2016-0160). As a result, this update incorporates the depreciation and amortization rates on common assets which were approved as part of the 2017-2018 Tx Decision issued September 28, 2017.

Depreciation expense has also been updated to reflect the changes to in-service additions as noted above to reflect lower capital spending. The total impact of these changes on the applied-for 2018 revenue requirement is an increase of $4.5 million as compared to previously presented revenue requirement.

Table 9: Total Distribution Depreciation and Amortization Expense ($ Millions)

Description	Historic				Bridge	Test				
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Depreciation Expenses	313.0	336.2	349.0	359.8	362.6	383.9	406.4	418.9	438.3	453.5
Total Amortization Expenses	8.5	11.1	10.5	12.0	17.8	17.3	16.2	18.8	18.6	17.4
Exclude Other Regulatory Amortization	0.5	1.1	1.9	3.2	3.7	4.2	4.5	4.7	4.9	5.0
Total	**321.0**	**346.2**	**357.6**	**368.7**	**376.7**	**397.1**	**418.2**	**433.1**	**452.1**	**465.9**

Exhibit Reference: C1-6-1

1.5 TAXES OR PILS

The changes to cost of capital parameters, capital expenditures, and OPEB result in changes in tax calculations which are summarized in Table 10.

Table 10: Corporate Income Taxes ($ Millions)

	2018	2019	2020	2021	2022
Regulatory Taxable Income	251.4	265.3	274.9	302.6	304.9
Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%
Subtotal	**66.6**	**70.3**	**72.8**	**80.2**	**80.8**
Less: Credits	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)
Total Income Taxes	**65.4**	**69.0**	**71.5**	**78.9**	**79.5**

Exhibit Reference: C1-7-2-1

2. CHANGES THAT DO NOT IMPACT REVENUE REQUIREMENT

2.1 CHANGE IN VEGETATION MANAGEMENT STRATEGY

Historically, Hydro One's approach to routine maintenance was focused on clearing corridors completely and maintaining hazard trees on an eight-year cycle. Deferrals in vegetation management spending has resulted in Hydro One's maintenance cycles to exceed this cycle length.

Pursuant to the OEB's decision in proceeding EB-2013-0416, Hydro One retained CN Utility Consulting to conduct a comprehensive trend analysis of its vegetation management program to show year-over-year comparisons in unit costs and a best practices study similar to a study it conducted for Hydro One in 2009. The report and its findings are provided in Section 1.6 of the Distribution System Plan.

These findings led Hydro One to initiate a review of the vegetation management program to improve its efficiency and impact, as documented in Exhibit C1, Tab1, Schedule 2. Although changes were intended to build the foundation for a long-term strategy intended to shorten the average maintenance cycle, the vegetation management program was still focused on clearing high impact right-of-way corridors completely on a cycle of four to eight years (8,500 km per year), with tactical maintenance on lower impact right-of-ways (4,250km per year) and removal of hazard trees.

Since the Application was filed, Hydro One has continued to further explore opportunities for continuous improvement in vegetation management and innovative approaches working with Clear Path Utility Solutions LLC. ("Clear Path"), an expert in utility vegetation management. A quantitative workload study was conducted by Clear Path which measured Hydro One's maintenance backlog and future workloads and recommended a vegetation management strategy designed to improve the condition and reliability of Hydro One's right-of-ways. Clear Path's study is provided as Attachment 2 to this Exhibit.

Based on Clear Path's recommendations, Hydro One has developed a new vegetation management strategy that maintains corridors on a three-year cycle, focusing on defects rather than completely clearing vegetation in a corridor. This defect-based approach will address vegetation that poses a public safety or reliability threat because it is either (a) growing into or will grow into energized equipment within the three-year maintenance cycle, and/or (b) dead/dying vegetation that will likely cause system interruption and/or equipment damage within the maintenance cycle.

The new vegetation management strategy will consist of three components:

1. **Defect Correction Program**
   The Defect Correction Program is the primary planned work program designed to ensure that one third of Hydro One's distribution network (34,666 km) will be patrolled yearly to identify and correct vegetation defects.

2. **Public Safety and Reliability Program**
   The Public Safety and Reliability Program will provide additional clearing on sections of the distribution system as needed; including such maintenance activities as: responding to customer requests, addressing trouble calls, planned tree pruning and removal, right-of-way widening, right-of-way floor clearing, mitigating emerging forest health issues, herbicide application or other integrated vegetation management treatments.

3. Quality Assurance and Quality Control Program

The Quality Assurance and Quality Control Program will manage and measure the success of its vegetation management investment. In addition to ongoing program management, Hydro One will also undertake work quality assessments, annual treatment effectiveness audits and detailed outage investigations to provide feedback into the continuous improvement process.

This approach to vegetation management will allow Hydro One to eliminate its backlog more quickly and improve the overall condition of its right-of-ways by 2022. Hydro One forecasts the 2018 cost of $149.6 million for vegetation management will not change with the new vegetation management strategy, as Hydro One views the 2018-2022 period as transitional, and Hydro One anticipates incurring transition costs with this new approach. Hydro One is cautiously optimistic that, once the transition is complete, vegetation management costs may decrease by 2023.

This new strategy should also result in improved reliability outcomes by addressing defects that can lead to tree-related outages. Hydro One anticipates addressing approximately 700,000 defects in 2018 over 34,666 kilometres. Historically, Hydro One has measured its units of accomplishments as kilometres actively managed. While kilometres actively managed remain a relevant measure of activity, the success of the vegetation management programs will be further defined by the number of defects completed each year.

The changes to the vegetation management strategy has resulted in a change to the 2018 target in the Distribution OEB Scorecard for “Vegetation Management – Gross Cyclical Cost per km $” presented on page 20 of the updated Distribution Business Plan (Attachment 1).

Hydro One anticipates this new approach will achieve similar benefits but on an accelerated pace due to the increased system coverage enabled by a shorter cycle and a refined scope. The new strategy will quickly reduce the maintenance backlog and enable program optimization. The shorter cycles will improve public safety, reliability, and asset condition providing a more detailed understanding of current and future workloads. Shorter cycles will also reduce customer and environmental impacts due to more frequent, less impactful maintenance.

2.2 UPDATE OF COST ALLOCATION TO NEW ACQUIRED CUSTOMER CLASSES AND COMPARISON OF BILL IMPACTS

As discussed in Section 2.2.3 of Exhibit G1, Tab 3, Schedule 1, Hydro One developed adjustment factors for use in the 2021 Cost Allocation Model ("CAM") to ensure that the costs allocated to the six new acquired residential and general service rate classes (AUR, AUGe, AUGd, AR, AGSe and AGSd) appropriately reflect the cost of serving the customers in these rate classes. Hydro One continues to believe the overall methodology used to develop the adjustment factors is appropriate. However, upon further consideration, Hydro One submits that it is appropriate to also include the cost of distribution stations in its adjustment factor calculations. The proposed change, rationale and results of making this change are described in the following sections.

The updated cost allocation, rates and bill impacts evidence provided below was prepared with reference to Hydro One's 2021 and 2022 revenue requirement as proposed in the Application as of June 2017. The changes to the 2021 and 2022 revenue requirement that will result from the updates discussed in Section 1 of this Exhibit are not captured by the updated evidence provided below. Hydro One notes that the 2021 revenue requirement of $1,684 million shown in Table 2 of this Exhibit is only $4 million (0.2%) higher than the revenue requirement underpinning the revised cost allocation, rates and bill impacts that are presented in the sections that follow. As such, the difference in revenue requirement will not materially impact the analysis and conclusions that are presented below.

2.2.1 Including Distribution Station Equipment in the Calculation of Adjustment Factors

In Exhibit G1, Tab 3, Schedule 1, section 2.2.3, Hydro One stated that adjustment factors were developed to align the amount of gross fixed assets ("GFA") in USofA accounts 1830 to 1860 (i.e. poles, towers, fixtures, overhead/underground conductors and devices, line transformers and meters) allocated by the CAM for these locally used assets with the amount of GFA specifically required to serve the new acquired rate classes. Upon further consideration since filing its Application, Hydro One has added distribution station equipment (USofA accounts 1815 to 1820) to the assets that should be included in the adjustment factor calculations. Similar to the assets covered by USofA accounts 1830 to 1860, distribution stations can be considered "local" assets that are essentially used to serve just the new acquired rate classes. As such, it is appropriate and necessary that USofA accounts 1815 and 1820 also be included in the GFA adjustment factor calculations.

The change in the GFA adjustment factor in turn impacts the calculation of the NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab, which are adjusted using the same methodology as described in the Application.

Similarly, the depreciation adjustment factor has also been revised to include the depreciation assigned by the CAM to USofA accounts 1815 to 1820 for the new acquired rate classes using the same methodology as described in the Application.

In addition, Hydro One has also made a correction to two items: i) a correction to the 2015 year-end GFA values used for Haldimand and Norfolk in determining the GFA adjustment factor, and ii) including USofA 1830-5 Secondary poles in the calculation of the depreciation adjustment factor. The impact of these corrections is minor and is noted for the sake of transparency. The changes to the allocation of overall costs, shown below, are mainly driven by the proposed change to the allocation of distribution station equipment.

2.2.2 Costs Allocated to the Acquired Classes

The 2021 CAM has been updated with the revised adjustment factors as described above. Adding distribution station equipment costs to the adjustment factor calculations has reduced the costs allocated to the new acquired rate classes by about $5.5 million, or 12%, when compared to the 2021 CAM included in the Application as of June 2017. The revised costs allocated to each of the acquired rate classes are shown in the "O1 Revenue to Cost Output Sheet" provided in Attachment 3. The revised CAM has also been provided in MS Excel format as Q-01-01-03.xlsx. As a result of this change, the updated revenue-to-cost ratios of the six new acquired rate classes are much closer to the OEB-approved range, as shown in Table 11 below.

Table 11: Impact of Updated Cost Allocation on Revenue-to-Cost Ratios

Rate Class	2021 R/C Ratio from the CAM	
	Evidence (June 2017)	Updated Cost Allocation
UR	1.10	1.10
R1	1.10	1.10
R2	0.97	0.97
Seasonal	1.11	1.10
GSe	1.00	1.00
GSd	0.93	0.92
UGe	1.01	1.00
UGd	0.91	0.90

Rate Class	2021 R/C Ratio from the CAM	
	Evidence (June 2017)	Updated Cost Allocation
St Lgt	0.95	0.95
Sen Lgt	0.96	0.95
USL	1.11	1.10
DGen	0.82	0.82
ST	0.89	0.89
AUR	0.86	0.93
AUGe	0.59	0.73
AUGd	0.43	0.63
AR	0.78	0.84
AGSe	0.74	0.81
AGSd	0.53	0.68

2.2.3 Proposed 2021 and 2022 Rates for the Acquired Rate Classes

Hydro One's proposed 2018, 2019 and 2020 rates (as of June 2017) are not affected by the proposed cost allocation changes to the new acquired rate classes.

As a result of the update to the 2021 CAM, the costs allocated to each rate class in 2021 have changed. As such, some of the proposed 2021 and 2022 rates are also impacted as discussed below.

Proposed 2021 Rates

The revenue-to-cost ("R/C") ratios as determined by the 2021 CAM are the starting point for the 2021 rate design. As shown in the 2021 Rate Design sheet provided in Attachment 4, most of the rate classes have R/C ratios within the OEB-approved range and require no further adjustment. The four rate classes whose R/C ratios require adjustment are the AUGe, AUGd, AR and AGSd acquired rate classes.

With the updated 2021 CAM, the R/C ratios of these four acquired rate classes are already quite close to the OEB-approved range (AUR and AGSe are already within the approved range). As such, Hydro One is able to move the R/C ratios of these four rate classes to within the approved range in 2021 without the need to mitigate bill impacts by phasing in the R/C ratio adjustment over two years, as was previously the case. Using the methodology described in Exhibit H1, Tab 1, Schedule 1, section 2.2, shifting the R/C ratios of these four classes to within the approved range requires shifting about $1.4 million of revenue requirement to the four acquired rate classes from the UR, R1, Seasonal and USL classes with the highest R/C ratios. This represents a decrease in the $3.4 million in revenue requirement that was previously being shifted away from the UR, R1, Seasonal and USL classes. However, the impact on the rates for these existing rate classes is small given that the change in shifted revenue represents only about 0.3% of the total revenue to be collected from these four classes.

The implementation of the revised adjustment factors in the 2021 CAM results in lower proposed 2021 rates for five[1] of the six new acquired rate classes as compared to the rates proposed.

Proposed 2022 Rates

The 2022 revenue requirement by rate class is derived using the same methodology as described in Exhibit H1, Tab 1, Schedule 1, section 2.1, which updates the 2022 rates to reflect the 2021 to 2022 change in revenue requirement and the 2022 load forecast. As shown in the 2022 Rate Design sheet provided in Attachment 5, the R/C ratios of all rate classes are within the OEB-approved range and require no further adjustment. The updated 2022 rates for the acquired AUGe, AUGd, AGSe and AGSd rate classes are

[1] The rates for the AUR class did not change as they were previously within the approved R/C range.

lower as compared to the rates proposed, given that no further R/C ratio adjustments were required in 2022.

2.2.4 2021 and 2022 Bill Impacts for Acquired Customers

In this Application, Hydro One proposes that the Acquired Utilities' rates remain frozen until the rebasing of costs in 2021. Therefore, the acquired customers' base distribution rates at the end of 2020 remain at the same level as when they were acquired by Hydro One. For former Haldimand County Hydro and Woodstock Hydro customers this means that their 2020 base distribution rates are the same as their 2014 rates in effect at the time they were acquired. For former Norfolk Power customers, the acquisition took place in 2013, but the 1% acquisition rider was increased to effectively freeze Norfolk customer's rates at 2012 levels, consistent with the purchase agreement, and so their 2020 base distribution rates are effectively the same as their 2012 rates.

Hydro One's evidence on bill impacts as provided in Exhibit H1, Tab 4, Schedule 1 shows the 2021 bill impacts based on the difference between Hydro One's 2021 proposed rates for the new acquired rate classes and the existing (frozen) rates that these acquired customers will be charged in 2020.

The bill impact comparison was provided consistent with the OEB's Filing Requirements. However, this comparison is misleading with respect to appropriately assessing the impact of Hydro One's application given that the proposed 2021 rates are being compared against rates that were set seven to nine years ago.

To provide a more meaningful assessment of the impact of Hydro One's application on acquired customers, Hydro One has compared its proposed 2021 and 2022 rates against what the Acquired Utilities' rates would have been had they ***not*** been acquired by Hydro One ("No Acquisition" scenario).

Under the "No Acquisition" scenario, the three Acquired Utilities are assumed to have filed either a Price Cap IR or Cost of Service/Rebasing rate application with the OEB annually from when their rates were last approved. Each utility is assumed to have filed a Cost of Service/Rebasing application consistent with the RRF (i.e. four years after their last rebasing under 3rd generation IRM and then every five years thereafter). For rebasing years, the distribution rates are assumed to increase by 6.3% which represents the average OEB-approved increase in base distribution rates for the residential and general service < 50kW rate classes of all distributors whose rates were rebased in 2015, 2016 and 2017[2]. For the remaining years, the Price Cap IR adjustment is applied based on the actual OEB-approved inflation, productivity and stretch factors until 2018, at which point they are held constant. Details of the distributors and rebasing increases used to establish the 6.3% value, as well as the annual inflation, stretch and Price Cap IR adjustment factors assumed for each Acquired Utility, are provided in Attachment 6.

<u>Bill Impact Assessment</u>

Table 12 shows the Hydro One proposed 2021 charges compared against the 2021 escalated Acquired Utility charges under the "No Acquisition" scenario. For reference purposes, the Acquired Utilities' charges at the time of acquisition are also included in Table 12.

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[2] This is consistent with the approach used by the OEB to assess the appropriate increase to apply in the setting of base distribution rates for Algoma Power Inc. and Hydro One Remote Communities Inc. as part of their distribution rates applications.

Table 12: Hydro One proposed 2021 charges compared against 2021 escalated Acquired Utility charges

Service Area	Rate Class	Monthly Consumption (kWh/kW)	Acquired Utility Charges at the time of Acquisition		2021 Escalated Acquired Utility Charges		2021 Hydro One Propsoed Charges		2021 Hydro One Proposed VS Escalated Acquired Utility Charges	
			DX Bill ($)	Total Bill ($)	DX Bill ($)	Total Bill ($)	DX Bill ($)	Total Bill ($)	DX Bill (%)	Total Bill (%)
Woodstock	Residential	750	$29.97	$112.72	$35.68	$118.58	$30.78	$115.13	-13.7%	-2.9%
	GS < 50 kW	2,000	$57.43	$287.80	$73.77	$304.57	$61.22	$290.83	-17.0%	-4.5%
	GS 50-999 kW	61,239/177	$461.41	$10,254.36	$709.16	$10,522.82	$795.26	$10,312.47	12.1%	-2.0%
Norfolk	Residential	750	$38.78	$120.43	$45.24	$127.56	$37.70	$122.75	-16.7%	-3.8%
	GS < 50 kW	2,000	$86.73	$314.60	$105.94	$335.23	$74.05	$305.00	-30.1%	-9.0%
	GS 50-4,999 kW	57,223/161	$780.99	$9,778.33	$1,118.11	$10,191.76	$980.44	$9,958.07	-12.3%	-2.3%
Haldimand	Residential	750	$35.46	$119.41	$41.42	$125.52	$37.70	$122.75	-9.0%	-2.2%
	GS < 50 kW	2,000	$63.94	$296.91	$75.70	$309.14	$74.05	$305.00	-2.2%	-1.3%
	GS 50-4,999 kW	50,917/143	$741.13	$8,979.21	$769.02	$9,008.54	$893.84	$8,884.92	16.2%	-1.4%

The results in Table 12 show the following:

- All residential customers in the new acquired rate classes will see lower distribution charges ranging from -9% to -17%, and lower total bills ranging from -2% to -4%.
- All GS<50 kW customers in the new acquired rate classes will see lower distribution charges ranging from -2% to -30%, and lower total bills ranging from -1% to -9%.
- Norfolk GS>50 kW customers will see a -12% decrease in their distribution charges and a -2% decrease in their total bills.
- Haldimand and Woodstock GS>50 kW customers will see an increase in their distribution charges of +16% and +12%, respectively, but these distribution increases are ***more than fully offset*** by Hydro One's proposed reduction to their retail transmission service rates (RTSR), resulting in a decrease in their total bill of -1% and -2%, respectively.

One of the contributors to the higher distribution charges for the new acquired GS>50 kW rate classes is, in part, the use of higher PLCC values in Hydro One's 2021 CAM, which result in the allocation of more costs to the GS>50 kW classes. This more fairly reflects the cost to serve high peak demand customers consistent with the principles underlying the OEB's cost allocation methodology. The higher PLCC values used by Hydro One are based on a Minimum System Study originally approved by the OEB in EB-2008-0187, with further updates approved by the OEB in EB-2013-0416. The results of the Minimum System Study are not expected to change materially with the addition of the Acquired Utilities given that Norfolk and Haldimand have a mixed density customer base similar to Hydro One, and the acquired utilities represent a relatively small addition to Hydro One's total assets and customer base. The PLCC values used by the Acquired Utilities in their cost allocation models are generic default values established by the OEB in 2006 and are not based on a specific minimum system study. The lower PLCC values used by the Acquired Utilities resulted in a shifting of costs from their GS>50 kW customers to other customer classes.

Another contributor to the higher GS>50 kW acquired rate classes' costs is the direct allocation of metering and billing related costs associated with serving interval metered customers. These rate classes attract a share of the metering and billing costs based on the number of interval metered customers within the rate class. Hydro One believes that its treatment of these directly assigned costs, most recently approved by the OEB in Hydro One's 2015-2019 distribution rates application (EB-2013-0416), results in a better alignment with the principle of cost causality.

As previously noted, the increase in distribution charges for the new GS>50 kW acquired rate classes is fully offset by Hydro One's proposed RTSR rates for these classes, which are significantly lower than the existing RTSRs used by the Acquired Utilities. The difference in RTSR rates is largely explained by the fact that Hydro One's RTSR model allocates transmission charges to rate classes based on their contribution to transmission system peaks, for network charges, and Hydro One distribution system peaks, for connection charges. The "peak contribution" calculations use Hydro One's forecast of load shape by rate class, which was developed with the most recently available actual hourly customer consumption data. This methodology follows the OEB's guidelines on setting RTSR as per Chapter 11, section 11.3.2, *OEB Electricity Distribution Rate Handbook* (March 29, 2001). By comparison, the Acquired Utilities set their RTSRs using the OEB's RTSR Adjustment Workform, which allocates transmission charges to rate classes based on changes to their share of charge determinants (kWh or kW) applied to original RSTR calculations which were based on rate class load shapes that have not been updated in over ten years.

Table 13 shows the Hydro One proposed 2022 charges compared against the 2022 escalated Acquired Utility charges under the "No Acquisition" scenario. The 2022 results are very similar to the 2021 results given that there is no rebasing or further R/C ratio adjustments in 2022.

Table 13: Hydro One proposed 2022 charges compared against 2022 escalated acquired utility charges

Service Area	Rate Class	Monthly Consumption (kWh/kW)	Acquired Utility Charges at the time of Acquisition		2022 Escalated Acquired Utility Charges		2022 Hydro One Propsoed Charges		2022 Hydro One Proposed VS Escalated Acquired Utility Charges	
			DX Bill ($)	Total Bill ($)	DX Bill ($)	Total Bill ($)	DX Bill ($)	Total Bill ($)	DX Bill (%)	Total Bill (%)
Woodstock	**Residential**	**750**	$29.97	$112.72	$35.95	$118.86	$31.59	$115.97	-12.1%	-2.4%
	GS < 50 kW	**2,000**	$57.43	$287.80	$74.39	$305.21	$62.74	$292.41	-15.7%	-4.2%
	GS 50-999 kW	**61,239/177**	$461.41	$10,254.36	$714.48	$10,528.83	$815.24	$10,335.06	14.1%	-1.8%
Norfolk	**Residential**	**750**	$38.78	$120.43	$45.64	$127.98	$38.69	$123.78	-15.2%	-3.3%
	GS < 50 kW	**2,000**	$86.73	$314.60	$106.88	$336.20	$76.04	$307.07	-28.9%	-8.7%
	GS 50-4,999 kW	**57,223/161**	$780.99	$9,778.33	$1,127.73	$10,202.63	$1,005.40	$9,986.27	-10.8%	-2.1%
Haldimand	**Residential**	**750**	$35.46	$119.41	$41.85	$125.97	$38.69	$123.78	-7.6%	-1.7%
	GS < 50 kW	**2,000**	$63.94	$296.91	$76.43	$309.90	$76.04	$307.07	-0.5%	-0.9%
	GS 50-4,999 kW	**50,917/143**	$741.13	$8,979.21	$776.86	$9,017.40	$916.32	$8,910.32	18.0%	-1.2%

The detailed bill impact calculations for each Acquired Utility by rate class, as summarized in Tables 12 and 13, are provided in Attachment 7.

3. CORRECTED HISTORICAL ROE FIGURES

On June 29, 2017, Hydro One filed a letter with the OEB correcting its historical ROE figures. The letter is provided as Attachment 8 to this Exhibit.

Distribution Business Plan 2018-2023

December 8, 2017

INTERNAL and CONFIDENTIAL

Table of Contents

Strategy and Business Objectives

Corporate Vision, Values and Strategy

Hydro One Limited is a purpose-led and values-driven company. Earlier in 2017, Hydro One launched the values that are integral to the company and to its communities. Those values include:

- Safety comes first;
- Stand for people;
- Empowered to act;
- Optimism charges us; and
- Win as one.

Hydro One Limited's strategic vision and business goals are consistent with and included in the business plans for Hydro One. This strategy will involve executing a number of strategic initiatives as follows:

- Optimization of the Core;
- Innovation in the Core; and
- Building Scale and Diversifying the Business through M&A.

Optimization and Innovation in the Core

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

Hydro One Limited's commercial orientation means that the company will be focused on customers, demonstrate corporate accountability for performance outcomes, and drive company-wide efficiency and productivity. Understanding customers' needs and preferences and delivering distribution system outcomes that are valued by customers are critical to Hydro One Limited's future success. Hydro One Limited will excel at managing relationships with key stakeholders including customers, Indigenous communities, employees, governments and regulators.

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

Circumstances & Challenges

Hydro One Networks (Hydro One or the Company) is the largest electricity distributor in Ontario. Hydro One serves more than 1.3 million customers in largely rural and suburban areas across Ontario, with approximately 123,000 circuit kilometers of lower-voltage power lines, 1.6 million poles and over 1,000 distribution and voltage regulating stations.

Geography

Hydro One's service area is one of the largest in North America. It is predominantly rural, with below average customer density by land area, higher than average tree density, and a higher than average number of storms, especially in winter, that damage the distribution system on a regular basis. Hydro One maintains over 104,000 kilometers of rights-of-way. The majority of the company's distribution power lines are located along roadways, and about one-quarter of the lines are off-road, requiring the use of special equipment for access and maintenance.

Reliability

Reliability performance is affected by vegetation, equipment performance, geography, and exposure to adverse weather, and as a result, the reliability of Hydro One's distribution system varies by location. In addition, much of Hydro One's distribution network uses a radial circuit design to cover large areas. A radial circuit design does not provide the redundant power supplies that are common in urban areas. These factors increase both the frequency and duration of power outages and also increase the time and cost of restoring power when outages occur.

Aging and Deteriorating Infrastructure

Many of Hydro One's assets are approaching or beyond the end of expected service life. While replacement decisions are based on actual asset condition, age is an indicator of an increasing requirement for asset replacements over the business planning period. For example, Hydro One currently has 280,000 wood poles (17% of fleet) that are beyond their expected service life of 60 years and 279 station transformers (23% of fleet) that are beyond their expected life of 50 years. If no replacements are made in the next five years, the number of wood poles beyond their expected service life rises to 400,000 (25% of fleet) and the number of transformers beyond their expected service life rises to 507 (41% of fleet). Assets that remain in use beyond their expected service life generally demonstrate higher failure rates. Significant investment is required to maintain the system in a reliable state.

Rising Cost of Power

Customers are experiencing increasing and, in many cases, unmanageable electricity bills. These increases have been driven by many factors, including investments in electricity generation, and material changes in generation fuel mix, from lower-cost coal to greater reliance on cleaner and more efficient natural gas, nuclear and renewable generation. In addition, conservation and demand management (CDM) initiatives have increased costs, on a kWh basis, as predominantly fixed system investment is recovered over lower total Ontario Demand. All of these factors, combined with the need for Hydro One to replace deteriorated assets and invest in the distribution system, have increased customer bills significantly. While Hydro One does not control external factors, it is mindful of the overall impact these costs have had on customers and customers' willingness and ability to pay rates that support needed investment in Hydro One's distribution system. Under the Fair Hydro Plan, the majority of customers will see an average reduction of 31 per cent on their monthly bills, meaning an annual savings of about $600. Furthermore, electricity rates will not increase beyond the rate of inflation for four years.

Business Objectives

Hydro One Distribution's business objectives are directly aligned with the Ontario Energy Board's (OEB) *Renewed Regulatory Framework* (RRF), as shown in the table below.

Hydro One's Values and Business Objectives

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace for employees and the public
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide reliability consistent with customer expectations
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts

In order to achieve its business objectives, Hydro One continues to devise new approaches to serve its customers, form its Distribution System Plan, and operate and maintain its assets, while maintaining a strong commitment to safety and the environment. These initiatives are discussed in the sections following.

Customer Focus

Customer Engagement for Developing the Distribution System Plan

Hydro One's objective is to engage with customers consistently and proactively. Hydro One has a three-pronged approach to engaging its distribution customers: formal customer engagement, stakeholder engagement and other on-going forums through which Hydro One interacts with its distribution customers. The company's full spectrum of customer initiatives is designed to: (i) increase the company's understanding of customers' needs and preferences; (ii) enhance Hydro One's ability to provide services that meet these needs; (iii) produce outcomes that are valued by customers; and (iv) result in an improvement of customers' overall satisfaction with the service they receive.

In the summer of 2016, Hydro One undertook a comprehensive customer engagement initiative to identify customer needs and preferences and incorporate findings in Hydro One's Rate Filings and Business Plans.

Hydro One engaged Ipsos, a global market research company, to assist in the design, execution, facilitation, and documentation of this customer engagement initiative.

Results of Customer Engagement

The customer engagement process produced the following key findings that are consistent with the Distribution System Plan and Distribution Business Plan set out in this document:

- Keeping costs as low as possible is customers' top priority. This preference is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. Many customers believe that total electricity costs are approaching being unaffordable;
- Maintaining reliable electricity service is consistently second priority to cost. Power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, is the primary concern. Some customers have capacity challenges and want more access to power in order to grow their enterprises. Customer service improvements are not something for which customers are willing to pay higher rates;
- Large customers are more concerned with the reliability of service they currently receive than residential and small business customers. However, although this group of customers is more inclined to value better reliability, they are not willing to entertain the corresponding rate impact;
- All large customer segments prioritize the renewal program that focuses on replacing equipment that affects reliability ahead of other options for improving reliability. Other

options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages; and
- Willingness to accept a rate increase to maintain and improve service level is limited. The majority of residential and small business customers are unwilling to accept higher rate impacts for better reliability; large customers generally accept that investments are needed; however they expect Hydro One Networks Distribution Business to exhaust all operational efficiencies before raising rates. At present, there is limited acceptance of any of the illustrative rate impact scenarios, even to maintain the current levels of reliability and service.

How the Distribution System Plan reflects Customer Needs and Preferences

Hydro One's Distribution System Plan reflects its general assessment of customer needs and preferences. Customer needs and preferences have been incorporated into the Distribution System Plan in the following ways:

- Pacing of investments in order to minimize rate impacts and offset the effects of a reduced load forecast. This includes managing asset replacement rates and, where appropriate, accepting potentially increased reliability risk to reduce or defer capital spending requirements in order to minimize customer rates;
- Implementing a number of productivity and efficiency initiatives to reduce unit and operating costs;
- Improving power quality for Large Distribution Account (LDA) customers by creating an operations, maintenance and administration (OM&A) program to assist customers with power quality investigations, and a capital program to install power quality meters, surge arrestors, and improve grounding; Increasing funding for reliability enhancement projects specifically targeting LDA and mid-size industrial customers. These projects will be selected to improve system reliability where performance concerns have been raised. Investments may include installing lightning arrestors, new switches, automatic sectionalizing devices, or creating feeder ties to improve restoration time. The funding for these investments will increase by approximately $3 million annually starting in 2018 from the current level of approximately $1.5 million per year; and
- Focusing on improving reliability of the worst performing feeders in the Province by improving sectionalization and automation of these feeders. This will allow controllers to quickly isolate faults and restore power to the majority of effected customers soon after the issue is identified. This program will annually invest between $14 million in 2018 and $20 million in 2022.

Customer Initiatives

In order to provide better service for Hydro One customers, the following major customer initiatives have been, or are currently being, implemented and will deliver cost savings and improved customer experiences: eBilling and High Bill Alerts, web redesign, remote disconnect and bill redesign.

Indigenous Relations

Hydro One's strategy as it relates to Indigenous relations is designed to ensure that the Company remains committed to developing and maintaining relationships with Indigenous communities that are based on mutual respect. Hydro One's Distribution business serves the majority of the Indigenous communities in Ontario and in many cases the needs of these communities are unique. Hydro One's ongoing engagement with Indigenous communities reflects the issues faced by these communities, and the evolving commercial, legal and policy requirements necessary to develop and maintain strong relationships.

Hydro One has multi-faceted relationships with Indigenous communities, and our management believes that there are many opportunities to strengthen and extend our relationships. Indigenous communities are involved in a variety of customer engagement activities. For example, Hydro One's customer engagement initiative in preparation for its 2018-2022 Distribution System Plan included Indigenous customers and over-sampled this group relative to their size within the total customer base, to ensure that we reliably captured the needs and preferences of this important customer group.

Hydro One has also developed a comprehensive Indigenous Relations Strategy Framework to guide our Indigenous relations and engagement. The key goal for Hydro One is to become the primary business partner to Indigenous communities by 2021. The key objectives to meet that goal are: 1) Become Top of Class: Fully integrate Indigenous relations into each Line of Business; 2) Become Primary Utility Partner: Create business, technical, knowledge and advocacy partnerships; and 3) Support Indigenous Leaders: Work with communities by supporting future leaders

Hydro One is actively pursuing a number of key initiatives that support a number of commitments made in the Framework:

- Hydro One engaged with the Ontario Energy Board in the development of an on-reserve First Nations electricity rate. Hydro One supported the OEB's work to develop meaningful solutions to the issues. As a result, the Government of Ontario announced in the spring of 2017 a new First Nations rate;
- Over the past year Hydro One has also successfully offered and continue to offer a new service model to several Ontario First Nation communities that focuses on in-community, face-to-face interactions, to ensure that customers understand and have access to all available programs. This service involves representatives from Hydro One's Customer Service and Indigenous Relations teams visiting First Nations communities around the

province to meet with Chiefs and Councils to conduct information sessions and hold one-on-one sessions with individual customers. During these meetings Hydro One is signing up interested customers for available conservation programs, collaborating with community service organizations such as the United Way to help low-income customers, and ensuring that customers who qualify are taking advantage of the Province's Ontario Electricity Support Program;

- Hydro One engaged with Indigenous representatives related to the company distribution rates application for 2018-2022; and
- The development of training for the Executive Leadership on Indigenous Relations. The curriculum and delivery platforms have been identified for the Executive Leadership Education. Indigenous Relations delivered a web based cultural awareness learning course and will deliver an in class course and experiential learning to Hydro One's leadership team, including all staff at the Director level and above.

The Distribution System Plan to Achieve Business Objectives

System Planning Process

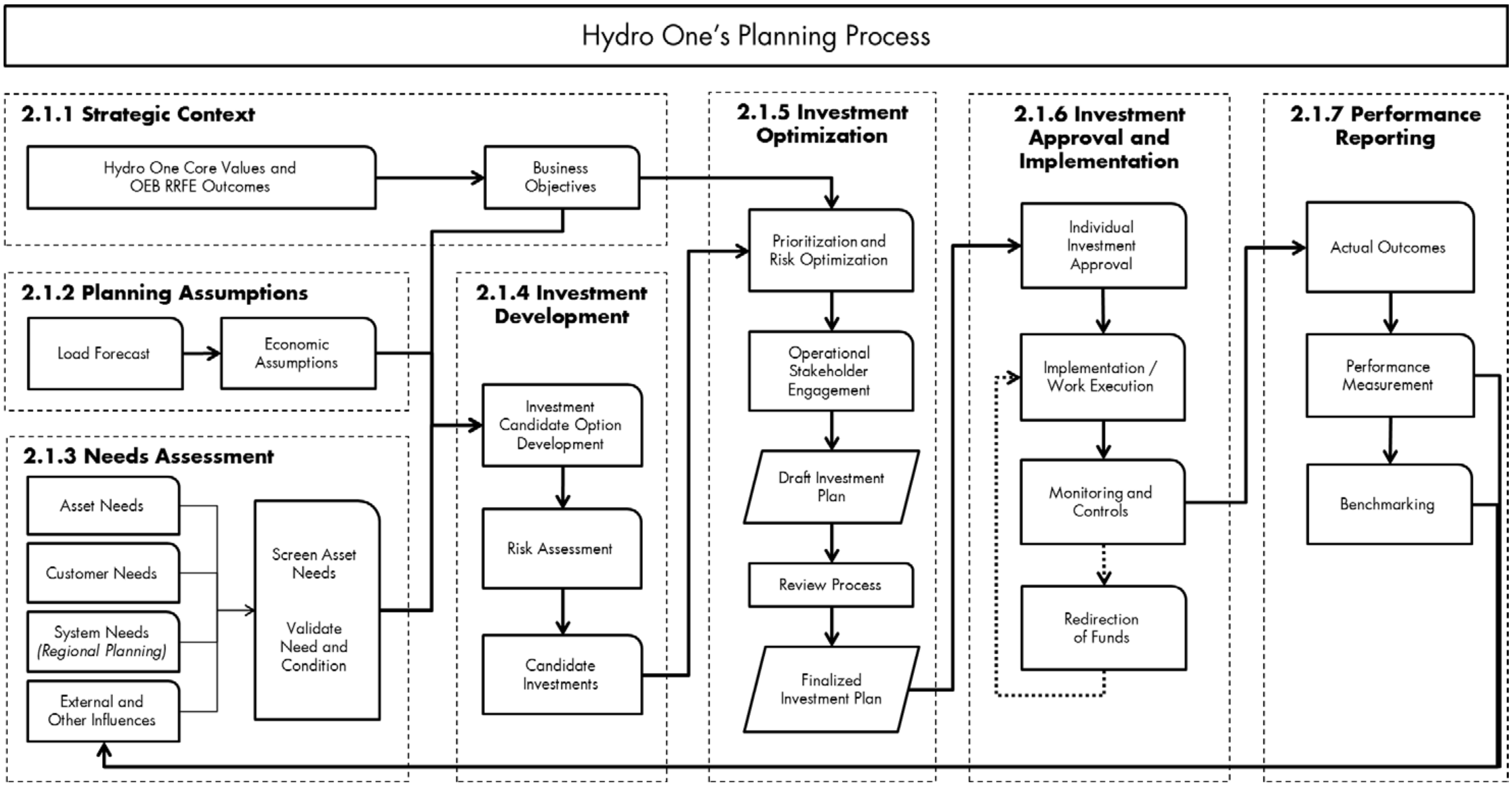
Hydro One Distribution's asset management and system planning process is designed to identify and scope the optimal timing of asset maintenance and capital investments in order to mitigate risk to Hydro One's business objectives, while optimizing total cost and managing customer rate impacts. It includes an ongoing cyclical process that develops an annual budget for OM&A and capital investments, and a five-year planning forecast that is consistent with the OEB's filing requirements for a consolidated five-year capital plan. All investments follow this same process. The planning process cycle in 2016, which underpins Hydro One's investments in its Distribution System Plan, includes the 2018 to 2022 period.

The Hydro One planning process consists of seven stages and is outlined in the figure below.

1. **Strategic Context**: Incorporation of strategic direction from Hydro One's Board of Directors and Executive Leadership Team that is used to focus the identification of needs and appropriately prioritize the candidate investments.
2. **Planning Assumptions**: Incorporation of load forecast and economic assumptions to guide the development of investments.
3. **Needs Assessment**: Assessment of needs based on the existing assets, customer needs and preferences, system requirements and other influences.
4. **Investment Development**: Development of candidate investments to address the identified needs.

5. **Investment Optimization**: Risk-based Prioritization of the proposed investments to yield an optimized investment plan.
6. **Investment Approval and Implementation**: Management of the investments within the optimized investment plan from planning, final approval and through execution to project completion.
7. **Performance Reporting**: Monitoring the plan through a set of performance metrics.

Hydro One's Investment Planning Process



Distribution System Plan

Hydro One's Distribution System Plan reflects the outcome of Hydro One's 2016 investment planning process. It prioritizes and paces its investment plans over the 2017 to 2022 planning period to align (i) identified customer needs and preferences; (ii) responsible stewardship of Hydro One's distribution system; and (iii) customer rates. This distribution system plan has been submitted to the OEB and is currently under regulatory litigation. While the Distribution System Plan and its associated outcomes have not materially changed since it was filed, Hydro One continues to develop innovative approaches that will improve reliability without increasing the cost of the work program.

Summary of Investment

A summary of 2018 to 2022 distribution capital expenditures is set out in the table below. The resultant rate changes are a 5.7% increase in 2018 and an average annual increase of 3.4% from 2019 to 2022.

Description	2018	2019	2020	2021	2022
Sustainment	300	369	386	400	481
Development	230	240	233	232	233
Operations	27	43	6	6	8
Common Projects and Programs	75	89	82	73	75
Total	**$ 632**	**$ 741**	**$ 707**	**$ 711**	**$ 797**

The breakdown of the budget according to the OEB's RRF is set out in the following table:

Description	2018	2019	2020	2021	2022
System Access	155	158	161	164	168
System Renewal	249	319	337	357	445
System Service	82	93	86	78	68
General Plant	146	171	123	112	116
Total	**$ 632**	**$ 741**	**$ 707**	**$ 711**	**$ 797**

An overview of the main conditions driving the investments in each of the OEB-compliant asset investment categories is set out below.

System Access

System access investments enable new connections, line relocations, and service upgrades. Activities in this category are stable over the first four years of the investment plan, leading to increases in line with inflation. There is a significant increase in projected spending in 2022, reflecting the anticipated commencement of an end-of-life smart meter replacement program.

System Renewal

System renewal investments primarily consist of storm damage restoration, pole replacements, and distribution station refurbishments. Storm damage restoration costs are expected to remain stable over the planning period. The pole replacement program is expected to increase until 2020 to address poles that have reached the end of their expected useful life. The station refurbishment program is expected to continue increasing to reflect the growing number of assets expected to reach the end of their useful life.

System Service

System service investments accommodate increases in load that would otherwise limit the ability of the system to provide consistent service. Additionally, the modernization of the worst performing feeders will improve system reliability for specific poorly performing supply feeders. While system service investments are projected to fall slightly over the planning period, Hydro One expects variability from year-to-year based on specific investment needs.

General Plant

General plant investments include spending on transport and work equipment and on facility improvements. There is a significant increase in the spending from 2017 to 2020 to accommodate the new Integrated System Operations Centre (ISOC), which will replace the existing backup power system control and telecommunications management centers and accommodate a new security operations center to meet business and regulatory requirements.

Continuous Improvement

As part of Hydro One's emphasis on improving the customer experience, investment effectiveness, and business outcomes, the following refinements have been made since this plan was approved in 2016. These refinements will not impact funding requirements.

Adjusting Vegetation Management Approach

An accumulation of backlogged maintenance in Hydro One's vegetation management program has been identified as a large contributor to poor system reliability. As a result, Hydro One is implementing a new vegetation management strategy. This strategy places Hydro One on an industry-leading 3 year cycle that will reduce safety risks, improve reliability and improve customer satisfaction. The strategy will not require any increases to the existing funding requirements and is expected to realize significant benefits by 2021. This transformation will also improve unit cost in the long term.

Optimizing Sustainment Investments and Modernizing Worst Performing Feeders

Optimizing selected sustainment investments to focus on location-specific challenges will positively impact customer outcomes and lead to work bundling and greater operational efficiencies. For example, giving additional attention to the worst performing feeders is expected to improve reliability for some customers by up to 50%, due in part to the deployment of modern automation technologies on these feeders.

Incorporating Recent Innovations into the Existing Plan

Hydro One is evaluating a number of innovative approaches for incorporation into the business plan, including treating poles to extend their service life, installing modular distribution stations to improve operational flexibility, and increasing the use of data collected from smart devices to reduce operational costs.

Work Execution

Hydro One considered the ability to execute the work efficiently and the ability to secure planned outages to minimize impacts to customers. As a result it has planned the pace of sustainment work so that planned interruption impacts could be minimized.

Planning Process Enhancements

Hydro One has implemented a number of enhancements to its end-to-end investment planning process to improve the assessment of operational risks associated with reliability, safety, and the environment. These were identified as priority outcomes for Hydro One's customers and will help to rationalize and prioritize investments. Investment risk assessments will be based on available condition assessments that are consistent with utility best practices, and will be challenged and calibrated across Hydro One to drive consistency in sustainment, development and operational investments. This new process will be used to support redirection decisions and to build all future plans.

Additionally, a monthly redirection process will monitor variances to plan. The Redirection Committee will provide advice and direction on investment adjustments that are required to the business plan to address emerging business needs or to seize opportunities related to the planning and execution of Hydro One's Investment Plan. Typically, variances to plan can be grouped into categories including carryover, acceleration of investments, unforeseen investments, estimating variances, deferrals of work, reduction of scope or costs, and cancellations.

Benchmarking

The following examples are of benchmarking study findings or recommendations that have been accepted and are being implemented:

- *Finding on Station Refurbishment*: "The study found that Hydro One's station-centric approach is appropriate, given the system configuration and density within the service territory."
    - Due to the positive feedback on Hydro One's station-centric approach, the use of this refurbishment strategy will be increased over the planning period.

- *Recommendation on Vegetation Management*: "Bring the whole distribution system to a four to eight-year flexible cycle that is trued up each year to ensure backlogs do not creep back into the schedule."
    - Working with industry leading experts, Hydro One has developed and transitioned to a new defect based work specification that will support a 3 year vegetation management cycle. This will address backlogs, reduce safety risks, improve reliability and improve unit cost in the long term.
- *Recommendation on Pole Replacement Program:* "Where geography and/or pole density permit, consider the use of dedicated pole replacement crews."
    - In 2017 Hydro One completed 37% of its pole replacement program with dedicated crews and plans to continue using dedicated crews in the coming years.

Distribution In-Service Additions

Capital expenditures and additions to rate base can be a significant contributor to revenue requirement increases. Hydro One has taken a paced approach to its distribution capital program to address the needs and preferences of our customers and the condition and reliability of the distribution system, and to mitigate the effect of in-service additions on customer rates.

Hydro One has pursued efficiencies and renewal capital deferrals in 2018 to mitigate the impact of in-service capital on customer rates.

There are two significant, non-typical investments in Hydro One's Distribution System Plan that represent a substantial increase over historically approved levels. These investments include the ISOC in 2019 and the Advanced Metering Infrastructure ("smart meter") replacement beginning 2022, as discussed above.

In addition to the non-typical investments mentioned above, expected in-service additions over the 2018 to 2022 period that are needed to maintain the condition and reliability of the distribution system, are forecast to increase over time. In-service additions in 2018 are expected to be in line with the 2017 level. This was achieved through the deferral of discretionary capital work, such as, wood pole replacements, station refurbishments/replacements and line sustainment projects. The deferral of work in 2018 has contributed to an elevated level of in-service additions from 2019 to 2022.

Integrated Systems Operations Centre

The ISOC will serve as the backup center for the Ontario Grid Control Center and the Integrated Telecommunications Management Centre. The current backup facilities are currently at capacity and do not meet Hydro One minimum standards. The Security Operations Centre and an Emergency Operating Centre are included due to the risk and lack of a primary site for operations, monitoring and coordinated response for physical security threats, which are imperative for business continuity. Security Event Monitoring provides cyber surveillance monitoring services and will be provisioned with Data Centre capacity. The ISOC has a planned in-service of 2020 with capital spend of $10.5 million in 2018, $42.6 million in 2019 and $3.3 million in 2020.

Operations, Maintenance and Administration Expense

Summary of Distribution OM&A Budget ($ Millions)

Description	2018	2019	2020	2021	2022	2023
Sustaining	$ 334	$ 341	$ 349	$ 357	$ 360	$ 360
Development	$ 23	$ 22	$ 23	$ 24	$ 26	$ 26
Operations	$ 19	$ 20	$ 19	$ 20	$ 20	$ 20
Customer Services	$ 130	$ 129	$ 128	$ 128	$ 129	$ 129
Corp Common Costs & Other OM&A	$ 72	$ 70	$ 68	$ 66	$ 63	$ 66
Property Taxes & Rights Payments	$ 5	$ 5	$ 6	$ 6	$ 6	$ 6
Total	**$ 583**	**$ 586**	**$ 594**	**$ 600**	**$ 604**	**$ 606**

Distribution OM&A is forecast to increase over the 2018 to 2023 business planning period by approximately 1% yearly. Forecast OM&A reflects Hydro One Distribution's planned Custom Incentive Rates application for 2018 to 2022, which includes an Annual Adjustment Mechanism that is adjusted for inflation, distribution industry productivity, and a Hydro One Distribution productivity stretch factor. Actual OM&A performance over the business planning period is expected to vary with the amount of OM&A costs notionally recovered in OEB-approved rates, due to the productivity and efficiency initiatives incorporated into this Distribution Business Plan.

Corporate Common Costs

Hydro One utilizes a centralized shared services model to deliver its common services to its transmission and distribution businesses and to its affiliated companies. Each business and affiliate pays its share of these costs based on a cost allocation methodology developed by Black and Veatch Corporation and approved by the OEB, which utilizes a breakdown of activities and drivers based on cost causality principles.

Distribution Corporate Common Costs and Other OM&A Costs 2018 to 2023 ($ Millions)

Corporate Common Cost $M	2018	2019	2020	2021	2022	2023
Asset Management	$ 14	$ 14	$ 14	$ 14	$ 14	$ 14
Common Corporate Functions & Services	$ 85	$ 85	$ 85	$ 86	$ 88	$ 89
Information Technology	$ 77	$ 77	$ 73	$ 73	$ 73	$ 74
Cost of Sales	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3
Other OM&A	$ (108)	$ (110)	$ (107)	$ (110)	$ (114)	$ (113)
Total	**$ 72**	**$ 70**	**$ 68**	**$ 66**	**$ 63**	**$ 66**

Productivity Strategy

Hydro One has undertaken a number of productivity initiatives to reduce costs while maintaining or improving service quality and work outputs. Quantifiable improvements are included in the distribution business plan and corporate scorecards with clear accountabilities for delivering the savings. Savings targets are relative to a 2015 baseline to show continuity of prior commitments made as part Hydro One's corporate 'Good to Great' initiative. The baseline will be reviewed as part of the next planning cycle. The 2018-2023 Distribution Business Plan includes an incremental increase in productivity benefits over the previous plan.

Hydro One has implemented a robust governance structure around productivity reporting to ensure productivity savings are accurately reflected on corporate scorecards and that there is continuity of savings in the Business Plan. The largest value initiatives included in the Distribution Business Plan are related to:

- More effective Strategic Sourcing and Fleet rationalization;
- Reductions in administrative expenditures enabled by software enhancements and improved process execution; and
- Rationalization of IT spending.

The table below summarizes the cost savings anticipated from the initiatives that have been embedded in the Distribution Business Plan:

	$M	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Capital	Operations	$ 36	$ 34	$ 37	$ 37	$ 39	$ 38
	IT	$ -	$ 0	$ 0	$ 0	$ 0	$ 0
	Capital Total	**$ 36**	**$ 34**	**$ 38**	**$ 37**	**$ 39**	**$ 39**
OM&A	Customer	$ 3	$ 4	$ 5	$ 6	$ 6	$ 6
	Operations	$ 17	$ 20	$ 23	$ 24	$ 26	$ 27
	IT	$ 9	$ 10	$ 13	$ 13	$ 13	$ 13
	OM&A Total	**$ 29**	**$ 34**	**$ 41**	**$ 43**	**$ 46**	**$ 47**
Corporate Common	Operations	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2
	People and Culture	$ 1	$ 2	$ 2	$ 2	$ 2	$ 2
	Finance	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	CCC Total	**$ 4**	**$ 4**	**$ 4**	**$ 4**	**$ 4**	**$ 4**
	Grand Total	**$ 70**	**$ 72**	**$ 83**	**$ 84**	**$ 89**	**$ 89**

The major drivers of the savings in each category are highlighted below.

Operations

- Move-to-Mobile will increase field workforce efficiencies through the utilization of new mobile application technology to manage inventory, and document field work order management and enable onsite decision making;

- The vegetation management program will deliver savings from various initiatives such as Optimal Cycle Protocol, changes to inclement weather deployment and switching and grounding initiatives; and
- The cable locates program has been outsourced to significantly reduce the cost per unit.

Operations - Procurement

- Will achieve cost reduction by bundling multiple contracts with a single supplier and negotiating volume discounts across multiple categories and contracts; maximizing competitive pressure through multiple feedback rounds; and installing catalogue buying via new SAP tools and enforcement of compliance with procurement contracts; and
- Spend analytics and standardization of specifications will enable direct, like-for-like comparisons across bidders, reducing procurement costs and inventory requirements.

Customer

- The new eBilling solution will reduce the volume of paper bills and result in associated postage savings over the planning period. The department also anticipates approximately 500,000 self-service transactions by 2019 as a result of the Web Redesign project.

Information Technology

- 3rd party contractor rate reduction will reduce rate by 20-30% effective 2017;
- Backup and storage optimization will reduce SAP storage costs without a material change in risk profile; and
- Infrastructure and database decommissioning and reduced monthly server and database fees.

People and Culture

- Organizational changes have enabled labour efficiencies resulting in recently vacant positions not being backfilled.

Productivity and Outcome Measures Scorecard

Hydro One is accountable for identifying specific outcomes valued by its customers and demonstrating how the utility’s plans and proposed operating and capital expenditures deliver those outcomes. These outcomes are aligned with the four outcomes of the RRF; Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Hydro One identified potential metrics drawn from internal and external sources that include: Hydro One's past performance management metrics, benchmarking studies, scorecards and metrics of other utilities in the public domain. The identified metrics were screened to select metrics that are relevant, objective, measurable and actionable. The company benefited significantly from knowledge obtained by the consideration of cost trends, benchmarking of comparable utilities, and from its customer engagement in setting outcomes and performance metrics.

Metrics were selected that promote behaviors that will drive desired outcomes for customers, stakeholders and shareholders. The proposed framework aligns customer and distributor interests, supports the achievement of important public policy objectives, and places a greater focus on delivering long term value to customers.

The proposed measures have been selected based on guidance from the OEB's Handbook for Utility Rate Applications which indicates the OEB's key considerations for a utility's proposed outcomes and performance metrics reflects a focus on strategy and results, not activities:

- The need to demonstrate continuous improvement;
- Outcomes which are demonstrated to be of value to customers; and
- Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

The table below illustrates the draft productivity and outcomes measures scorecard that Hydro One is proposing in addition to the OEB distribution scorecard that is already in use. This scorecard has been filed in the 2017 Distribution application.

Productivity and Outcome Measures Scorecard

Distribution System Plan: Productivity and Outcome Measures

			Historical Results						Target	
RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2018
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	72%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	86%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	81%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,640	8,733
		Vegetation Management - Gross Cyclical Cost per	New Program							3,600
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	461,000	454,000
		OM&A dollars per customer	456	451	498	551	453	455	449	455
		OM&A dollars per km of line	4,723	4,676	5,109	5,654	4,719	4,773	4,712	4,773
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,200	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	6,900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	145	145
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.1	9.0
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.4	3.4
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.8	2.8
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.7	1.7
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		118	147	165	136	143	143

*There were no station refurbishment units matching the criteria completed in 2012

Revenue Requirement & Customer Bill Impacts

Distribution Revenue Requirement	2017	2018	2019	2020	2021	2022
OM&A	$ 593	$ 582	$ 586	$ 590	$ 595	$ 599
Depreciation	$ 390	$ 393	$ 413	$ 427	$ 445	$ 459
Return on Debt	$ 183	$ 199	$ 208	$ 219	$ 233	$ 243
Return on Equity	$ 253	$ 276	$ 289	$ 304	$ 324	$ 338
Income Tax	$ 49	$ 63	$ 67	$ 69	$ 76	$ 76
Revenue Requirement	$ 1,468	$ 1,512	$ 1,563	$ 1,609	$ 1,673	$ 1,715
Acquired LDCs OM&A Adder	$ -	$ -	$ -	$ -	$ 11	$ 11
Rate Riders	$ 11	$ 6	$ 6	$ 6	$ 6	$ 6
Other revenue impacts	$ (53)	$ (54)	$ (55)	$ (55)	$ (56)	$ (56)
Rates Revenue Requirement	**$ 1,426**	**$ 1,465**	**$ 1,515**	**$ 1,561**	**$ 1,634**	**$ 1,676**
Rate Increase Required, excl Load		**2.7%**	**3.4%**	**3.0%**	**4.7%**	**2.6%**
Estimated Load Impact		3.0%	0.2%	-0.2%	-2.3%	-0.3%
Rate Increase Required		**5.7%**	**3.6%**	**2.8%**	**2.4%**	**2.3%**
Est Total Bill Impact (R1 customer - 40%)		**2.3%**	**1.4%**	**1.1%**	**1.0%**	**0.9%**

Revenue requirement calculated above reflects the following structure:

- 2017 OEB approved revenue levels;
- 2018 rebasing year reflecting required revenues;
- 2019-2022 OM&A reflects revised OEB proposed Price Cap escalations; and
- 2019-2022 depreciation, return on debt and tax related revenues assume the implementation of a Custom Capital Factor.
- Acquired LDC's reflected in 2021

The revenue requirements calculated above have been adjusted since the Company filed Blue Page updates to the OEB in June 2017. The adjustments relate primarily to OEB issued cost of capital parameters and inflation factor that were released on November 23, 2017. The parameters result in an increased allowed ROE from 8.78% to 9.00%, and an increased allowance for short-term debt from 1.76% to 2.29%. Also, after reflecting for actual debt issuances in 2017, coupled with forecasted long-term debt rates in 2018, the allowance for long-term debt has increased from 4.33% to approximately 4.45%. Grossed up for taxes, these updates increase the revenue requirements in 2018 by approximately $16 million; of which $7 million relates to the ROE increase, with the remainder reflecting increases to the cost of debt and tax impacts. The OEB's inflation factor, which was reduced from 1.9% to 1.2%, has been reflected in the calculations above as a placeholder for the calculation of OM&A in 2019-2022. Each year the placeholder rate will be replaced with the actual inflation rate. OM&A in 2018 has been reduced taking into consideration feedback from the OEB as part of the decision on Transmission 2017 and 2018 rates. This update reduces OM&A by approximately $3 million by allocating more Corporate Management costs to the shareholder. Capital expenditures and associated impacts to rate base have also been updated to reflect reductions in common projects and accelerated productivity initiatives in the current Business Plan, however are largely consistent with levels previously filed in the Blue Page update. These updates are planned to be filed with the OEB in mid-December, and may also be adjusted to reflect costing for OPEB expenses and common asset depreciation rates reflecting the OEB approved common rates underlying the Transmission 2017-2018 rate application. Estimates for the OPEB expense update are currently under review and not available at this time, however will ultimately reduce the ask of revenue requirement.

Load Forecast Summary

Hydro One uses a number of methods, such as econometric models, end-use models, and customer forecast surveys to produce the load forecast required for its distribution business. This load forecast methodology is the same method that Hydro One has applied in previous Distribution Rate Applications (EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416). Similar methods are also used by major utilities throughout North America.

The forecasts presented are weather-normal at the wholesale level unless otherwise specified. Abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. This weather correction methodology was reviewed and approved by the Board in the Distribution Cost Allocation Review (EB-2005-0317).

Using this approved forecasting methodology; the forecast for the test years (2018 to 2022) is presented in the table below.

Distribution

	2017	2018	2019	2020	2021	2022
Number of Customers (by contract)	**1,291,963**	**1,300,519**	**1,309,221**	**1,317,972**	**1,326,734**	**1,335,373**
Energy (Consumption) Billed sales (GWh)	15,094	15,003	14,878	14,881	14,844	14,845
Demand Billed sales (GWh)	3,450	3,426	3,392	3,387	3,374	3,370
Sub-Transmission	4,912	4,877	4,828	4,818	4,807	4,808
Total Consumption Sales (GWh)	**23,457**	**23,306**	**23,098**	**23,086**	**23,025**	**23,023**
Demand sales (MW)	**11,925**	**11,848**	**11,739**	**11,731**	**11,692**	**11,685**

While the Provincial aggregate load growth is expected to decline, the customer count is expected to rise moderately. The decrease in load is mainly due to the impact of CDM and the current economic conditions. There are also pockets of load and customer growth expected to occur in Hydro One's service territory, primarily in areas that border major urban centers.

Acquired LDC's

Hydro One Distribution expects to continue to assess further opportunities to acquire other Ontario-based local distribution companies over the 2017 to 2022 business planning period. Consistent with OEB policies, the integration of acquired utilities for rate setting purposes will not occur until the conclusion of the OEB-approved rebasing deferral period. Hydro One Distribution plans to apply to the OEB for approval to close each of Norfolk, Haldimand and Woodstock to Hydro One's revenue requirement and rate base in 2021.

Acquired LDCs OM&A Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Norfolk	$ 3.1	$ 3.1	$ 3.2	$ 3.2	$ 3.3	$ 3.3
Haldimand	$ 5.0	$ 5.1	$ 5.1	$ 5.2	$ 5.3	$ 5.4
Woodstock	$ 2.1	$ 2.1	$ 2.3	$ 2.1	$ 2.1	$ 2.2
Total	**$ 10.2**	**$ 10.3**	**$ 10.6**	**$ 10.5**	**$ 10.7**	**$ 10.9**

Acquired LDCs Capital Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Norfolk	2.6	2.1	2.1	2.1	3.2	3.2
Haldimand	3.4	3.4	3.9	4.0	4.0	4.0
Woodstock	2.2	2.3	1.8	2.0	2.2	2.3
Total	**8.2**	**7.8**	**7.8**	**8.1**	**9.4**	**9.5**

Key Financial Results

Following is a summary of principal financial outcomes for Distribution for 2017-2022.

Key Financial Results	2017	2018	2019	2020	2021	2022
Revenue requirement	$ 1,468	$ 1,512	$ 1,563	$ 1,609	$ 1,658	$ 1,699
Net income	$ 244	$ 294	$ 300	$ 308	$ 303	$ 310
OM&A	$ 566	$ 580	$ 584	$ 592	$ 598	$ 601
Capital expenditures	$ 599	$ 632	$ 741	$ 707	$ 711	$ 797
Total rate base	$ 7,190	$ 7,672	$ 8,040	$ 8,455	$ 8,832	$ 9,209
Total fixed rate debt to rate base	50.0%	56.0%	56.0%	56.0%	56.0%	56.0%

Required revenue for Distribution aligns with that approved by the OEB for 2017. Forecast revenue requirement for 2018 through 2022 reflects Hydro One Distribution's planned Custom

Incentive Rates application, which reflects an Annual Adjustment Mechanism and a Custom Capital Factor. It is assumed that the Distribution business will achieve the allowed ROE throughout the business planning period, with the exception of 2017 and 2018. Shortfalls in financial performance is largely attributable to load impacts arising from lower load relative to the forecast embedded in the approved Distribution rate application for 2015-2017, and 2018-2022.

HYDRO ONE - FORESTRY SURVEY ASSESSMENT

Final Report
November 10, 2017

Confidential

Contents

1 EXECUTIVE SUMMARY

1.1 Introduction

The contents of this report represent the results of a comprehensive field assessment of Hydro One's electric distribution system to help determine the optimal vegetation maintenance cycle to reduce the occurrence of electric disruptions caused by vegetation and improve public safety at a reasonable cost.

Hydro One's maintenance cycle exceeds 8 years and was identified in recent program assessments, including an Ontario Energy Board (OEB) report as the key driver of program performance, each recommending the cycle be shortened to improve reliability, public safety, and cost performance.

As a key driver of overall performance, the optimal cycle is at the intersection between cost, defect, and reliability performance over a specified time horizon. The optimum cycle should result in little or no degradation in feeder performance between treatment intervals and before treatment costs begin to escalate.

The assessment was based on a statistically valid representative sampling of system conditions, future expected workload with historical cost and reliability data modeling to determine an appropriate cycle interval.

Conclusions contained in this report are based on a shift from current practices to a defect prevention based vegetation management program:

- *Defects are defined as:*
  - *Vegetation in contact or showing evidence of contact with energized conductors.*
  - *Trees, limbs, or portions thereof that are dead, dying, diseased, decadent, or structurally unsound located within the strike zone of energized conductors.*
- *Defects are a sub-portion of the tree population, most likely to cause a service interruption, or public safety issue and are easiest to identify and control with appropriate maintenance practices.*
- *Defects prevention is priority and the ultimate goal.*

It should be noted that in their current rate application, Hydro One has presented a long-term strategy to reduce system backlog and improve reliability. Although the filed strategy is an improvement on historical programs, the 3 year cycle strategy proposed in this report will generate similar investment outcomes in one third the time.

1.2 Defects Results

- Hazard Trees – hazard trees remained after work was performed at a system rate of 270 trees per 100 km worked. 432,000 hazards currently exist across the system as extrapolated from the survey. Another 657,000 are estimated to become hazards over the next 3 years.
- Contacts – 366,000 tree/brush-to-conductor defects exist across the system with another 630,000 estimated to contact over the next 3 years.
- Thirty percent of feeders had defects within 2 years after work was performed at an average rate of 3.3 defects per kilometer, 82% of defects were off-ROW contacts and hazard trees.
- Defects have a distinct and significant pattern of increase over time as the length of the cycle interval increases.

1.3 Reliability Results

- Off-ROW tree and branch failures cause approx. 90% of all outages
- Contacts are causing 6.5% of all outages and are the easiest to control with an optimal cycle and scope.
- Off-ROW hazard trees which remain under the current scope of work continue to negatively impact reliability performance within 2 years after work is performed, offering a significant opportunity for improvement.

1.4 Forecast Workload and Cost

- It is estimated that 2.1 million trees will need work over the first 3-year cycle to achieve base level defect control, 700,000 trees per year as compared to 800,000 under the current work scope. The major difference in approach is an optimized defect-based work scope combined with a strategic brush control regimen that significantly reduces cost per km from the current $11,000 per km to an estimated $3,000 per kilometer for the first full cycle.
- Cost modeling was based on unit price estimates utilizing Hydro One personnel to perform the work. Note: Pricing estimates used for this report have not yet been validated and Hydro One has not demonstrated the productivity levels necessary to achieve these results over a sustained period. It is expected that unit cost estimates and productivity assumptions will become more accurate after a period of working under a modified work scope and cycle.

1.5 Other Observations

- Heavy to moderate brush was observed on less than 5% of the spans surveyed, 53% of spans had no brush and 43% had low to very low brush density.

1.6 Key Findings

- **Maintenance Cycle** – The increase in the number of defects per km based on years since last worked found in the survey confirms a direct relationship between cycle intervals, defects, and reliability performance. Based on the survey data a 3 -year maintenance cycle is the optimal period before defects increase significantly which causes cost escalation and reduced reliability performance.
- **Work Scope** – The number of Off-ROW defects found in the survey confirms that the current work scope, in combination with the extended cycle, is the biggest contributor to less than desired reliability performance. It was evident that maintenance activities have been largely focused on areas within the ROW, leaving behind Off-ROW vegetation which is the major contributor to poor reliability performance.
- **Reliability Modeling** –By implementing an optimal maintenance cycle, modified work scope and an analytics based hazard tree program, it is reasonable to expect a 20% to 40% plus improvement in reliability by the end of 2020. An analytics based hazard tree program requires funding beyond the baseline maintenance levels.
- **Cost Modeling –** There is a reasonable probability, assuming that work scope is managed through a quality control effort, that the first 3-year maintenance cycle can be performed within existing funding levels. Cost for subsequent cycles may be significantly less as hazard trees and contact defects are controlled.
- **Feeder Prioritization** – The survey provides the data necessary to begin the transition to a shorter cycle interval with feeder prioritization based on voltage, defect volume, forecast cost and historical reliability results.

1.7 Recommendations

- Adopt an initial 3-year maintenance cycle first time through the system and re-evaluate prior to start of the second cycle. Alternative cycle intervals (2-5 years) may be introduced based on actual field conditions (3 years of data) matched to the desired outcome based on the intersection between defect, reliability, and cost.
- Revise work scope to focus on defects first (on and off ROW).
- Implement a Quality Control (QC) process to control scope and monitor work performance.
- Finalize and fully implement an outage investigation process to develop analytics for system awareness and continuous improvement.
- Implement a formal hazard tree program, part of which is incorporated into baseline cycle work and part of which is targeted work based on analytics.
- Implement work management and project management tools.
- Continue with workforce and work methods strategy.

Important Safety Observation

Recommendations contained in this report suggest a renewed emphasis on the identification and mitigation of hazard trees, with an estimated 1.1m trees needing work over the first cycle. Hazard trees, by definition, pose a risk not only to electric facilities but also to workers. Exposure to the dangers associated with climbing and/or felling hazard trees is likely to be greater than previously experienced. Additional precautions are advised.

2 SURVEY METHODOLOGIES

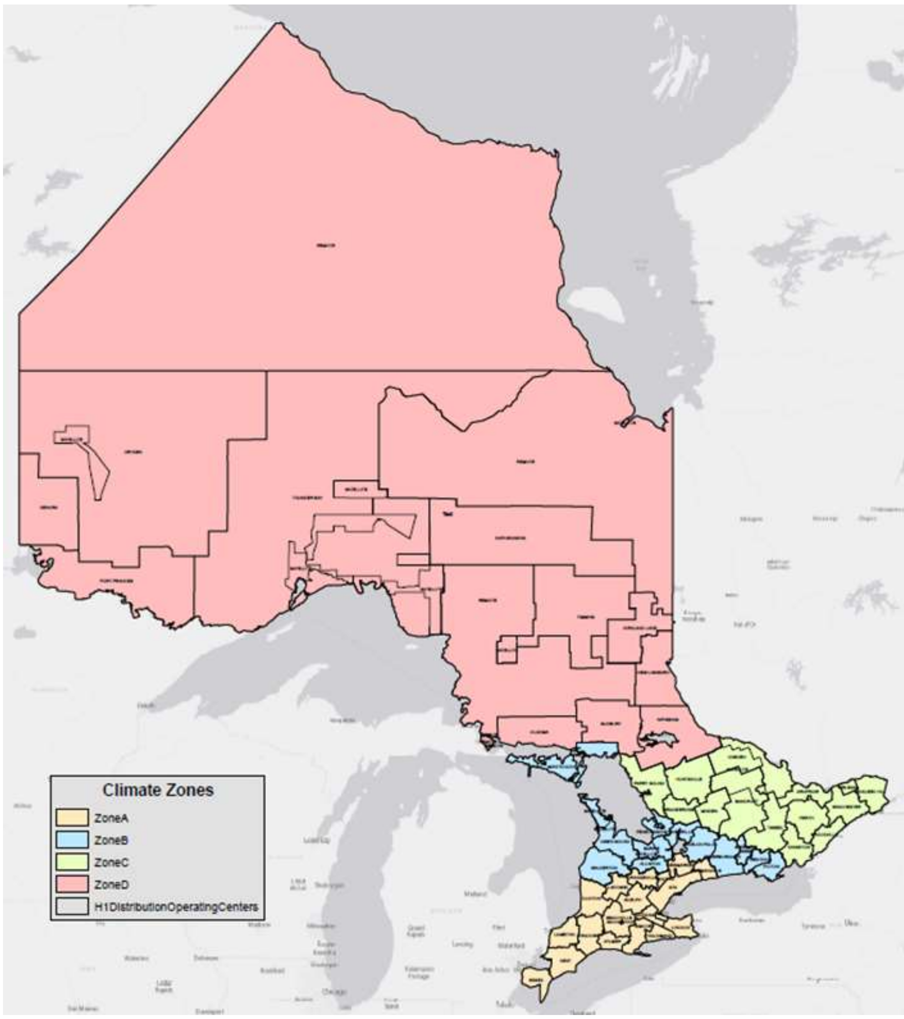


Figure 1: Map of HydroOne Territory showing Survey Zones

2.1 Survey Design

Hydro One operates one of the largest electric distribution systems in North America with a diversity of tree species and variable growing conditions. In order to minimize the impacts of this variability on survey results, the system was sectioned into four Climate Zones (Fig. 1, above) split between low and high voltage and further divided by years since last worked to create "slot classes" (Table 2, below). A representative number of survey samples were determined for each of the slot classes and the field data was collected by Arbor Metrics Solutions in May/June 2017.

Climate Zones
A – Agriculture/Suburban, Southeasterly part of Ontario surrounding GTA
B – Rural Cottage Country/Agriculture**,** East Central Ontario, North of GTA
C – Rural/Forested, Northeast Ontario
D – Forested/Remote, Northwest Ontario

Voltage		Years Since Last Worked			
Low	4.16kV – 22kV	0-2	3-5	6-8	9+
High	24.9kV – 44kV	0-2	3-5	6-8	9+

Table 1: Divisions Used to Create Survey Slot Classes

3 DEFECT ANALYSIS AND KEY FINDINGS

3.1 Defect Rate over Time

Years Since Last Worked	0 - 2	3 - 5	6 - 8	9+
Tree Contact Defects per KM on ROW	0.31	0.76	1.96	5.91
Tree Contact Defects per KM Off ROW	0.23	0.17	0.48	1.43
Brush Contact per KM On & Off ROW	0.07	0.45	0.44	4.59
Hazard Tree Defects per KM Off ROW	2.70	4.10	4.57	5.56
Total Defects Per KM	3.30	5.47	7.45	17.49

Table 2: Based on year last worked, defects per system KM by defect type

Table 2 (shown above) clearly illustrates the increase in all defect types at each interval after time of work:

- **0 – 2 years after work** – At this interval there should be few defects, but the data are showing defects at or shortly after work is performed at a rate of 3.3 defects per km. Most defects (82%) are off-ROW hazard trees. The remaining 13% are trees currently in contact with conductors, many of which are off-ROW trees.
- **3 – 5 years after work** – The overall defect rate increased 67% from the previous interval with contacts increasing 128% and hazards increasing 52%. The rate of brush contacts increased significantly with a rate 6.5 times greater than 0-2 years.

- **6 – 8 years after work** – The overall defect rate increased 36% from the previous interval and more than doubles the 0-2-year interval. Contacts doubled from the previous interval and increased four times over the 0-2-year period. Hazard trees increased at a lower rate of 11% over the 3-5-year rate
- **9 plus years after work** - The overall defect rate more than doubled from the previous interval and increased more than 5-times the 0-2-year period. Contacts increased more than 4-times the previous interval and 12-times the 0-2-year period. Hazards increased at a slower rate with a 25% increase over the previous interval and double the 0-2-year period.

Figures 2 and 3 (below) illustrates that current defects and projected defects follow the same pattern of increase over time. This outcome is not surprising as individual tree species have a typical genetic growth pattern and response to environmental conditions, which would naturally produce a similar increase over time.

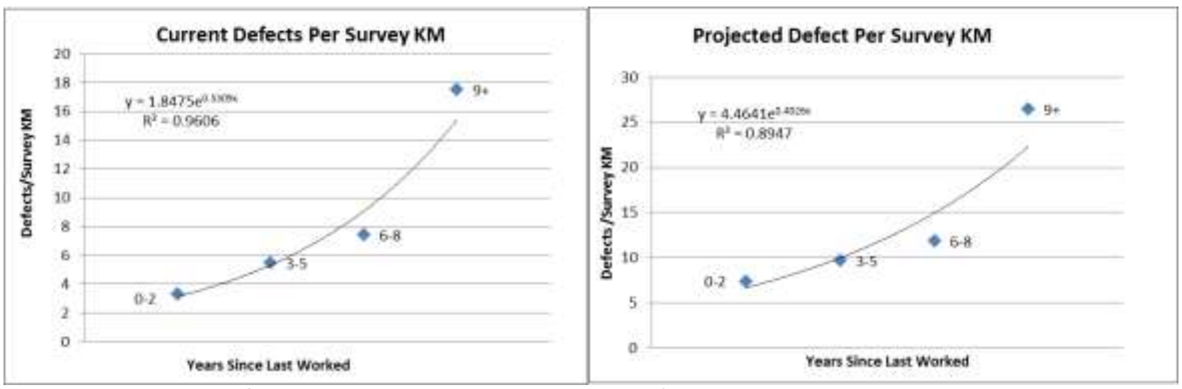
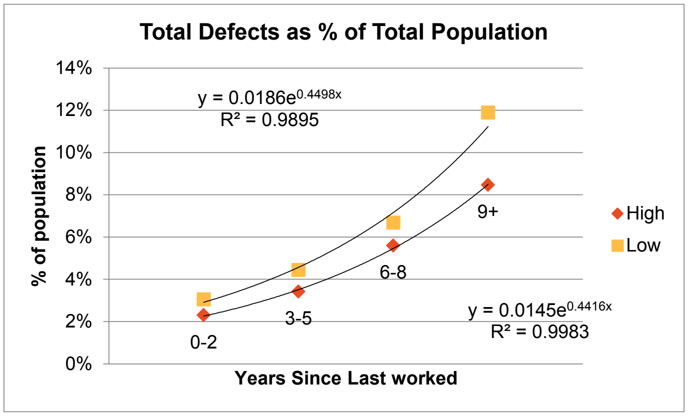
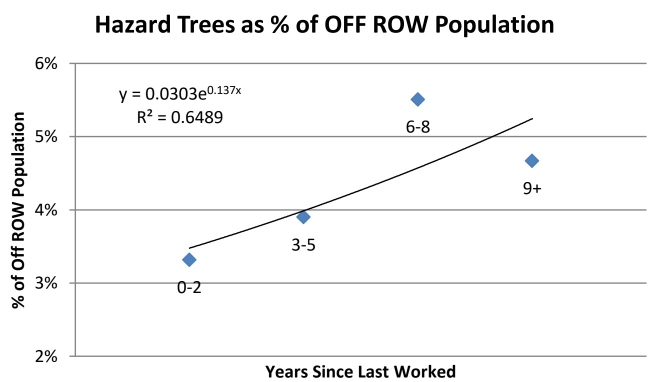


Figure 2 and 3: Current and projected increase in defect over time, based on year last worked

3.2 Defect Rate and Tree Population

Defects as a percentage of the tree population increased at each slot interval from time last worked (Fig. 4, below). Zero to two years after work, the defect to population rate was 2.3% for higher voltage lines and 3% for lower voltage lines indicating better clearing for high voltage vs. low voltage at time of work. At the 3-5-year point, the defect rates more than doubled on lower voltage lines to 4.4% and increasing 49% on high voltage lines to 3.4%. Lower voltage lines increased 50% again at the 6-8-year period to 6.7% and was five times greater than years 0-2 (11.9%) at the 9-plus period. Higher voltages slightly increased at the 6-8-year period (5.6%) and increased 4 times (8.5%) at the 9-year–plus period.





Figures 4 and 5: Current defects as a percent of a defined population

Hazard trees measured as a percentage of the off-ROW population increased steadily as the time interval increased from 3% to 5.5% at the 6-8-year mark then fell to 4.7% at the 9-year plus mark (Fig. 5, above). This is not fully explained except potentially due to a subset of trees naturally failing after a certain period keeping the percentage stable. *Note: Further analysis on hazards may be advantageous to fully understand the dynamics. Ideally there should be relatively few hazards remaining after work is performed with .5% to 2.5% projected mortality in subsequent years depending on the forest type. Random assessment of plots in unmanaged forest conditions relative to managed forest areas may be able to help with this determination. The survey found that just over 4% of the tree population adjacent to Hydro One facilities is considered a current hazard with the number doubling over the next 3 years.*

3.3 General Observations - Defects

Approximately 30% of feeders had defects within 2 years after being worked with hazard trees accounting for 82% of the total (at a rate of 2.7 hazards per km worked). Additionally approximately 7% of the remaining defects were due to contacts from trees located out of the ROW.

Eighty-eight percent of brush contacts were located on feeders 6 plus years since the date last worked (Fig. #). Seventy percent of the brush contacts were located on just 20 feeders which represented only 5% of the surveyed KM. Seventy-four percent of brush contacts were on voltages lower than 24.9kV.

Years Since Last Worked	0 to 2	3 to 5	6 to 8	9 Plus	Total
# of Brush Contacts	20	131	142	1009	1302
% of Brush Contacts	1.5%	10.1%	10.9%	77.5%	
Voltage Class	High	334	Low	968	
% by Class		25.7%		74.3%	

Table 3: Brush Contacts by year last worked and by voltage class

While single year analysis of all current and projected defects from the survey data (Fig. 6, below) cannot be considered statistically valid due to limitations of the survey design and a high degree of variability, a year over year look at the defect data shows a significant jump in defect rate between Year 3 and Year 4.

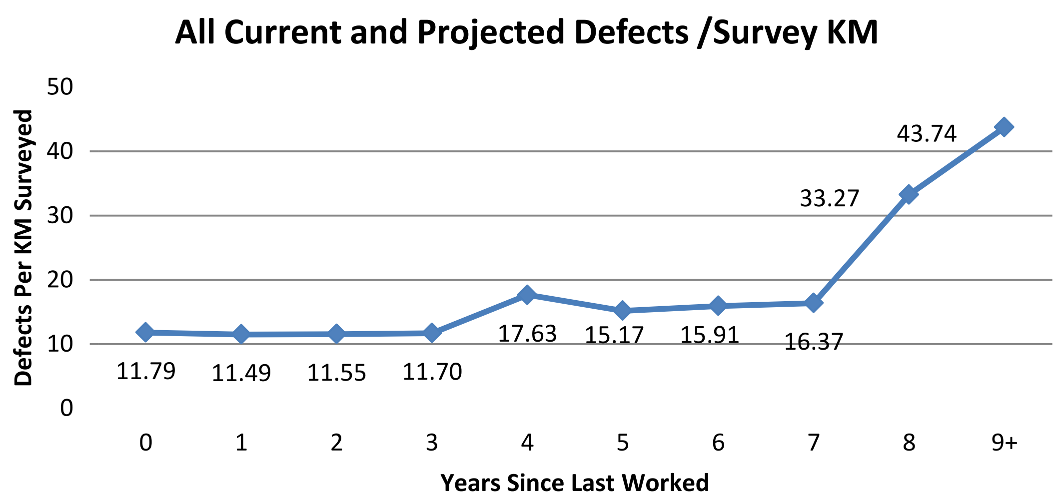


Figure 6: Total Current and Projected Defects per Survey KM based on single year analysis

3.4 Key Findings

Forestry work activities have generally been focused on clearing vegetation within the ROW boundaries, with a lesser emphasis on off-ROW vegetation, particularly hazard tree identification and mitigation.

- On-ROW work has been generally effective at controlling grow-in contact defects for the first 2 years after work is performed with 2% of the feeders surveyed having evidence of on-ROW contact related defects. This should be easily controllable through an effective QC program.
- The occurrence of hazard trees identified within 2 years after work presents an opportunity to reduce tree failures with a robust hazard tree program integrated into cyclical work.

Sections of feeders appear to have been worked off-cycle on an ad-hoc basis based on reliability concerns. Off-cycle work should be minimized or eliminated under an optimal cycle.

3.5 Conclusion

It is not unexpected that an extended maintenance cycle would lead to an increase in contact defects. Insufficient clearance relative to tree growth and cycle, removals untreated by herbicide and natural ingrowth all contribute to increased workload over time. Although, the number of hazard trees does not show the same obvious pattern of increase over time, this is primarily because the Off-ROW hazard trees are not a focus under the current work scope and a significant number remain in place in the years immediately following clearing work. The survey results clearly indicate that a shortened cycle interval for the maintenance work along with an increased focus on identifying and mitigating hazard trees will reduce workload over time resulting in improved reliability performance and lower costs.

4 RELIABILITY ANALYSIS AND KEY FINDINGS

4.1 Outage Rates over Time

Outage analysis in relationship with time since last worked was challenging due to many of the feeders having remedial work performed on different sections in different years and variability of weather events year to year. Unlike the defect analysis, we were not able to isolate outages based on date last worked on individual sections of line. The difficulties of analysis were compounded when viewing a 3-year outage outlook vs. 2016 standing alone.

All views of the outage data indicated a significant number of outages in years 1 and 2 after clearing work was last performed. The 2016 outage curve was significantly steeper when including force-majeure events and worth further analysis to fully understand the trends (Fig. 7 and 8).

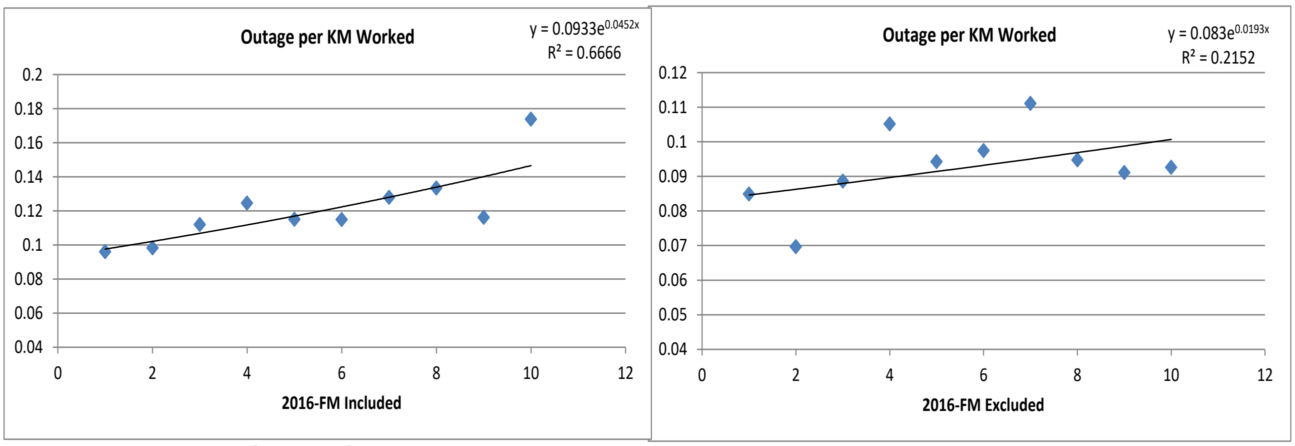


Figure 7 and 8: 2016 System Outages based on time last worked

4.2 Outage Rates by Climate Zone

Zone A has the steepest trend line over time but a lower starting point in the initial year after work was performed (Fig. 9). This correlated directly to the number of defects after work performed, at about half the system rate. This pattern may result from a lower tree density and fewer hazard trees in Southern Ontario or it could indicate that Zone A work activities controlled defects more effectively, resulting in better reliability performance for the first 3 years, degrading thereafter and ending with a similar result as other zones after 6 or more years.

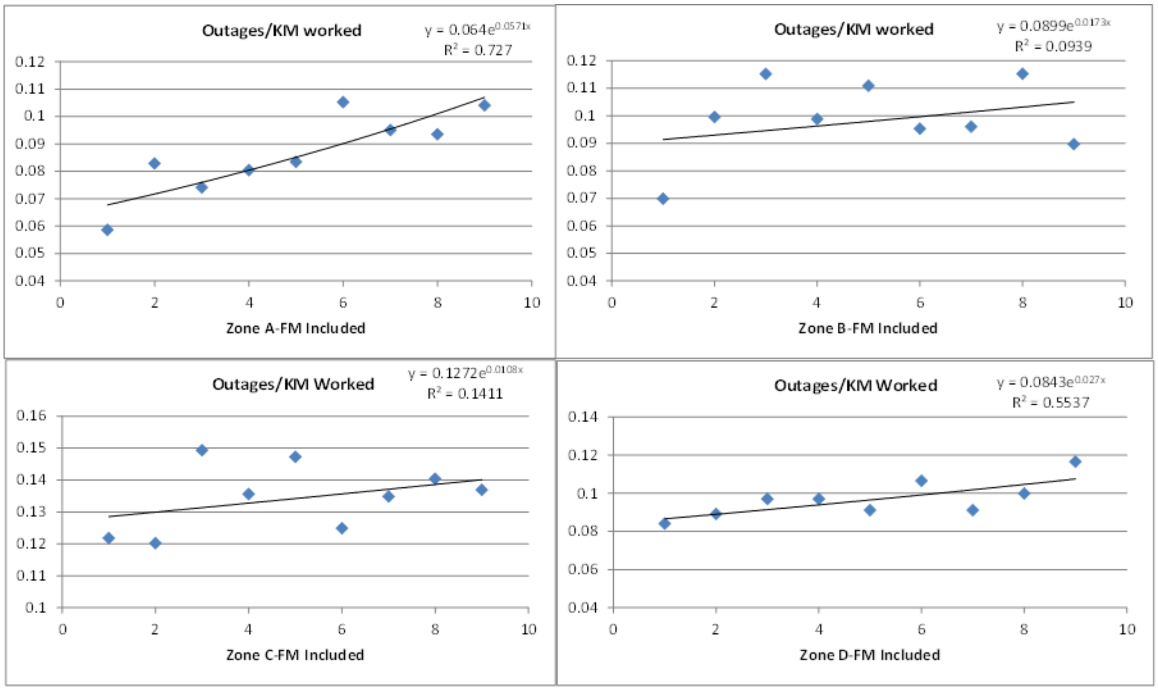


Figure 9: Three Years (2016-2014) Combined Outages by Survey Zone based on time last worked

4.3 Outage Field Investigation Results

Formal outage investigation was recently started with 262 records in the database. While still a relatively small number of records, we can start to draw certain conclusions with gains in confidence over time. Compiled information (Table 4) from field investigation finds that 90% of failures are from relatively small trees under 60cm in diameter, 21% were dead at time of failure, 50% had visible symptoms of disease, insects or structural defect and 59% were from 5 species of tree - *Balsam (24%), Popular (15%), Spruce (8%), Pine (8%), and Elm (4%).* Mitigating dead trees alone, through an increased focus on hazard trees and a shortened cycle will result in a significant reliability improvement.

Visible Symptoms	#	%	Age	#	%	DBH	#	%
Disease/Insect	35	13%	Juvenile	49	19%	0 - 20 cm	56	21%
Insect	28	11%	Mature	161	61%	20 - 40 cm	109	42%
Dead Trunk Fail	42	16%	OverMature	16	6%	40 - 60 cm	46	18%
Dead Uprooted	14	5%	Unknown	36	14%	60+	17	6%

Table 4: Results of Outage Field Investigations

Outage cause reported through the Hydro One outage recording systems and data from field outage investigations showed similar results (Table 5, below) with tree failures representing ~80% of all outages, branch failures ~10% and grow-in's 6.5%. Grow-ins should be virtually eliminated with a shortened maintenance cycle and corresponding work scope resulting in an immediate 6.5% reliability improvement.

	Field Investigations		Outage Reporting	
Outage Cause	# of Outages	% of Total	# of Outages	% of Total
Public Tree Cutting	5	2.00%		
Tree Branch	25	9.50%	1151	11.50%
Tree Fall In	209	79.70%	8,207	81.90%
Tree Grow In	17	6.50%	666	6.60%
Unable to find cause	2	0.70%		
Wildlife Tree Cutting	3	1.20%		

Table 5: Comparison of Field Investigation Results and Hydro One Outage Recording

4.4 Reliability Modeling

Using historical outage data and information on years since last worked, it is possible to create a model which forecasts the number of outages the system will incur moving to a modified cycle. Figures 10 and 11 (below) illustrate the number of outages and percent of outage reduction per year, after implementing a 3-year cycle with no changes to the current patrol standard. It is significant to note that the decrease in outages from only a cycle change flattens over time and additional reductions would require changes to the Dx standard and/or focused reliability efforts.

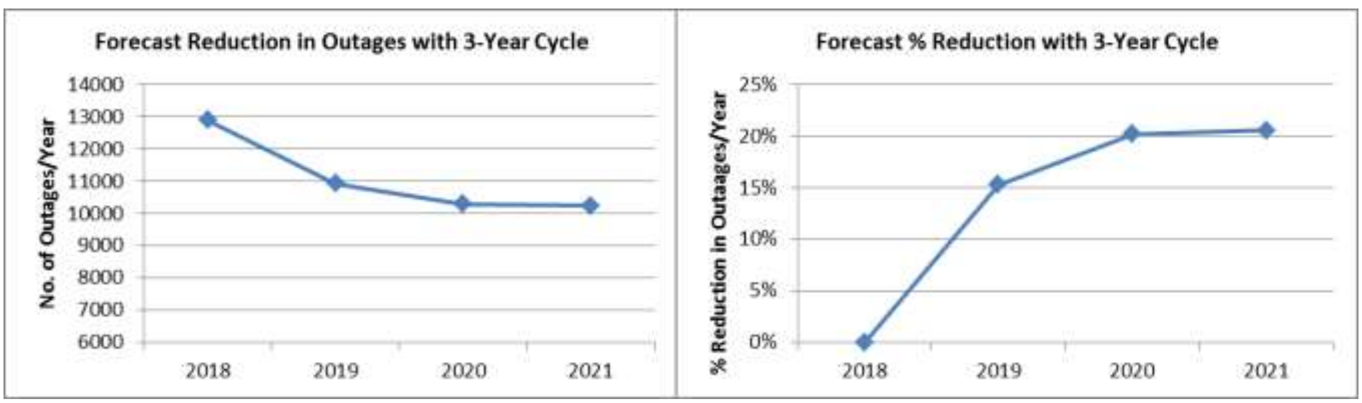


Figure 10 and 11: Forecast # of Outages (including Force Majeure) and % Reduction based on 3-Year Cycle

4.5 - Conclusion

Hydro One can reasonably expect a 20% to 40% (or better) reliability improvement moving to a shortened maintenance cycle, updating the patrol standard to match clearance requirements to cycle interval and implementing a more rigorous approach to hazard tree mitigation. As described above, modifying the cycle alone could produce a 20% improvement and based on field investigation results removal of dead trees could eliminate an additional 20% of the outages.

Improvements in tree-related reliability can lead to significant savings in other lines of business. A reduction in the number of outages results in less straight-time and overtime payroll for call center staff, trouble men and line crews. Additionally, there are avoided costs associated with a reduced number of damaged facilities.

5 COST/WORKLOAD ANALYSIS AND KEY FINDINGS

5.1 Current and Projected Workload

Combined Current and Projected Workload	Zone A	Zone B	Zone C	Zone D	Total Units of work
Contacts On-ROW	73,093	85,631	88,502	54,122	301,348
Contacts Off-ROW	94,597	94,463	83,488	48,135	320,683
Brush Contacts	41,175	102,430	111,500	120,519	375,625
Hazard Trees	129,408	243,165	517,607	199,193	1,089,372
Totals	338,273	525,689	801,097	421,969	2,087,028
Est. Population On-ROW	1,163,898	1,159,757	817,555	401,592	3,451,888
Est. Population Off-ROW	1,093,987	1,786,051	4,412,139	2,319,451	9,806,507
Totals	2,257,885	2,945,808	5,229,694	2,721,043	13,258,395

Table 6: Current and Projected Future Work Load by Zone

Sixty seven percent (67%) of the current and 3-year projected defect workload (Table 6) is related to off-ROW trees (contacts and hazard trees combined) suggesting a need for increased focus on Off-ROW vegetation, specifically hazard trees.

Projected hazard tree workload over the next 3-year period represents a substantial portion of the estimated off-ROW tree population, more closely resembling an unmanaged forest as opposed to a managed ROW corridor. Once hazard related defects are controlled (after the first full cycle), Hydro One could reasonably expect to see the annual hazard tree workload decrease by 60-70% more closely representing an expected annual tree mortality of 1-2%.

Hazard trees represent approximately 50% of the first cycle workload but they will be the costliest and most difficult to identify and mitigate, as a result accounting for around 70% of first cycle cost. Tree and brush contacts account for the remaining 50% of the workload, but will require only approximately 30% of the cost.

Assuming a shortened maintenance cycle is implemented and once the first cycle is completed, going forward the number of defects and future workload will be greatly reduced.

5.2 Cost Modeling

Using the forecasted workload (Table 6, above), diameter class breakdowns from the survey data and unit price estimates based on the assumption that Hydro One personnel will perform the work (Table 7), it is possible to create a cost model. The projected costs for line clearing work shown in Table 8 below, are based on a 3-year cycle that assumes 50% of the contacts workload will be pruned and 50% will be removed and 100% of hazard tree workload will be removed. Variance from these assumptions and actual achieved unit costs will impact actual cost results.

Estimated Cost of Unit Type					Unit Type Percent from Survey			
Unit Type	Zone A	Zone B	Zone C	Zone D	Unit Type	Diam On-ROW	Diam Off-ROW	Hazard
R1 (10-30 cm)	$125	$98	$102	$73	R1 (10-30 cm)	70.1%	69.3%	69.3%
R2 (30-60 cm)	$313	$245	$255	$183	R2 (30-60 cm)	27.2%	26.4%	26.4%
R3 (60-90 cm)	$500	$392	$408	$292	R3 (60-90 cm)	2.7%	4.4%	3.4%
R4 (>90 cm)	$1,000	$784	$816	$584	R4 (>90 cm)	NA	NA	1.0%
Prune	$125	$98	$102	$73	Inspect & Notify - calculated at annual $2.5M per zone			
Unit Price*	$162.80	$124.75	$138.75	$143.15				

*Weighted unit price based on 50/50 split of prune and removals and percent of removal class.

Table 7: Unit Cost Projections

Annual	Zone A	Zone B	Zone C	Zone D	Annual	3-Year Totals
KM	10,383	8,060	10,070	5,770	34,282	102,847
Defects	139,621	223,824	238,935	101,955	704,336	2,113,007
Cost (incl. insp./notify)	$25,230,852	$30,422,190	$35,652,051	$17,095,357	$108,400,451	$325,201,352

Table 8: Workload and Cost Projections by Zone for a Three Year Cycle

It should be noted that the above cost projections are for baseline minimum work necessary to mitigate defects over a 3-year cycle. Excluded are cost items such as customer demand work, enhanced hazard tree work, brush control, QA/QC activities, outage investigations and similar.

The projections are estimates based on the available data and can be influenced by many factors.

a. Negative influences
   i. Scope creep - maintaining scope is critical to avoid cost escalation.
   ii. Crew productivity – sustainable production to meet unit cost assumptions.
   iii. Hazard trees – underestimated degree of difficulty.
   iv. Work forecast margin of error +/- ~10%.
   v. Feeder prioritization and scheduling – worst first could result in unequal distribution of work (km vs. trees) over the cycle duration impacting the first year more than subsequent years.
b. Positive influences
   i. 2017 work activities can be leveraged to validate assumptions and optimize program operations.
   ii. Forecasted 3-year hazard trees are likely overestimated. Projecting 3-year hazard trees is challenging and current defect levels suggest it could be high.
   iii. Resource and Work Method Strategies – opportunity to optimize based on the new approach.
   iv. Reduction in demand, and unplanned work as the cycle progresses

5.3 Feeder Prioritization for Modified Cycle

The survey provides the necessary data to support feeder level cost modeling, cycle prioritization and ‘what-if’ analysis. The suggested approach is to establish a feeder prioritization weighting methodology using the following attributes:

- Time since last worked
- Feeder criticality
- Reliability performance
- Production attributes

A work plan can be developed using base level cost projections plus adders depending on the feeder objectives (i.e. 44kV and certain other critical feeders may want to exceed base level objectives).

5.4 Conclusion

Although study cost modeling is built on a set of assumptions that may need to be adjusted based on real-time results, it appears that base level control of contact and hazard defects (on and off ROW) on a 3-year cycle can be achieved within current budget constraints when implemented along with a rigorous well-defined Standard. Base level control of defects does not include additional work to further improve reliability, strategic brush control or other activities. If funding is available beyond base level work, it would be advisable to allocate additional resources to these activities.

6 CONCLUSIONS

Findings from this report are consistent with previous studies recommending a shorter maintenance cycle, specifically the 1998 ECI and 2016 CNUC studies. However, it should be noted that prior recommendations were not founded on a defect based approach nor did they back up their recommendations for cycle modification with hard data.

The current 8 years plus maintenance cycle and work scope employed by Hydro One are resulting in lower than desired reliability performance, elevated risk of employee/public safety incidents and high maintenance cost per km worked.

The survey found a direct correlation between cycle interval, defect load, and reliability performance suggesting the intersection where defects increase, reliability degrades, and maintenance cost per km is at the three-year mark as depicted in Figure 12 below.

In their current rate application, Hydro One has presented a long-term strategy to reduce system backlog and improve reliability. Although the filed strategy is an improvement on historical programs, the 3 year cycle strategy proposed in this report will generate similar investment outcomes in one third the time.

The survey and modeling suggest that implementing a 3-year maintenance cycle and an analytics based hazard tree program with associated management controls will improve reliability performance between 20% and 40%, reduce employee/public safety exposure and reduce long term cost.

Alternative 4 and 5-year cycles were examined and appear to have a lower year-over-year cost but would not provide desired reliability or public safety results. In addition, predicting vegetation conditions over a longer time horizon can result in excessive listing practices to account for the longer cycle thus lessoning cost advantages.

An initial 3-year maintenance cycle will allow Hydro One to get through the system in an accelerated period to mitigate existing defect load leading to a quicker path toward improved reliability and reduced safety risk. At the end of the first cycle, additional data and system awareness will be available to further refine and potentially adjust the cycle and scope.

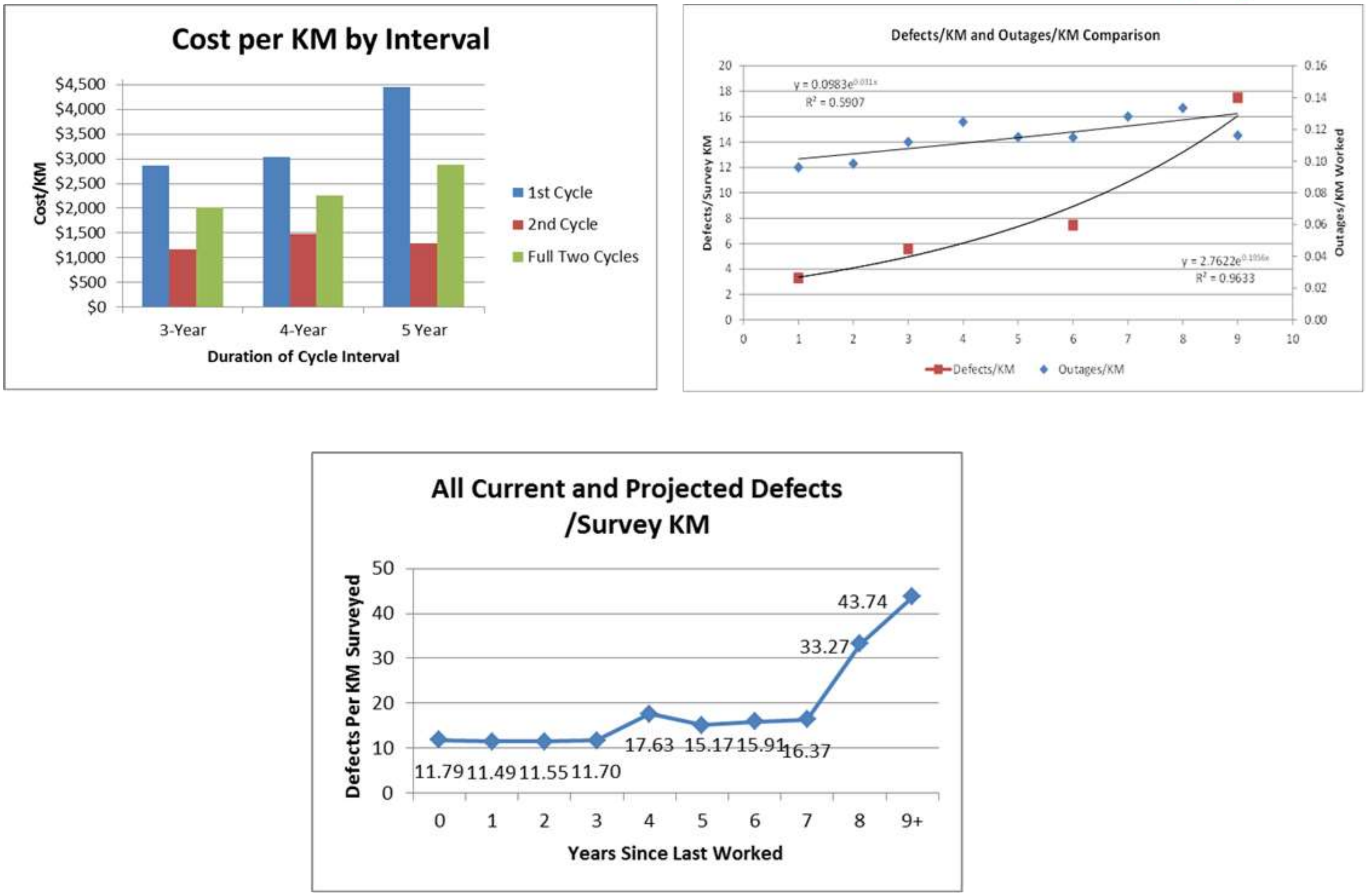


Figure 12 – Cycle impact on cost, defect and reliability

7 LISTS OF APPENDICES

Appendix A – Survey Methodology and Execution
Appendix B – Slot Class Distribution
Appendix C – Supplemental Survey Results

APPENDIX A – SURVEY METHODOLOGY AND EXECUTION

Sampling Methodology and Statistical Validity

The survey was conducted using statistically valid representative sampling methodology using data requirements developed by Hydro One, Clear Path Utility Solutions and Arbor Metrics. A sampling methodology using these variables was developed and validated by Dr. Milo Nosal, a statistical consultant and retired professor of Applied Statistics and Statistical Computing at the University of Calgary.

The following are excerpts from Dr. Nosal's report;
This raw field data will be classified into various classes according to actual powerline voltage, climatic zone, and years since the last maintenance.
Since actual probability distributions of field (population) values of these variables are entirely unknown, large sample asymptotic distribution theory for the means (averages) of the required variables will be used. In order to perform a statistical estimation of the actual unknown population field values of the required variables, this methodology will allow to calculate and construct confidence intervals for all required variables with any desired level of confidence. For practical customary reasons, it is recommended that the final estimation should be calculated using 90%, 95%, and 99% confidence levels. However, using this methodology, it will be possible to construct required confidence intervals for any required confidence level.
The critical issue at this stage is the determination of the required random sample sizes for the above defined data, classified by voltage/climate zone/years since last maintenance. As follows from the large random sample asymptotic distribution theory for the means (averages), random sample size of n = 50 or more observations from each voltage/climate zone/years since last maintenance class would be ideal for the confidence interval construction purposes. However, for practical purposes, a minimal random sample size of n = 30 observations from each class would be entirely sufficient. Thus, it is recommended that the class size between n = 30 and n = 50 be used for this sample survey design. However, it should be emphasized that if the final available sample size would drop below 30 for any class due to any circumstances like loss of data, it would invalidate the required conclusions. Further it should be emphasized that the sample selection for each voltage/climate zone/years since last maintenance class must be performed completely and entirely at random. This means that any sample within a given class must have the same probability of being selected for the survey. This should be accomplished using a random numbers generator.

Strata Tables

Hydro One currently completes their Vegetation Management Program on a feeder basis. Each feeder was coded into one of 32 "slot classes". Slot Classes were based off three key variables. A slot class is a unique combination of the three variables resulting in a sub-population of the entire system.

The three key variables are;
1. Four Climatic Zone. (See Section 2 for a map and a detailed description of these four zones).
2. Two Voltage Classes.
    i. 4.14kv, 8.32kv, 12.5kv, 13.8kv, and 22kv.
    ii. 24.9kv, 27.6kv, and 44kv.
3. Four Age groups since last cleared under the current Vegetation Management Program.

i. 0, 1 or 2 years since last cleared.
ii. 3, 4, or 5 years since last cleared.
iii. 6, 7, 8, years since last cleared.
iv. 9 years plus since last cleared.

The chart below shows the 32 Slot classes. The slot classes were numbered using two digits. The first digit is a letter corresponding with the climatic zone and the second digit is a number from 1 to 8 based off voltage and the number of years since last cleared. "A1" for example is in climatic zone A, last cleared 0-2 years ago, and is in the lower voltage group.

Key breakdown of Hydro One Utility Powerline Infrastructure

Climatic Zone A - km's Breakdown	0 to 2	3 to 5	6 to 8	9 plus
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	A1	A2	A3	A4
24.9kv, 27.6kv, 44kv	A5	A6	A7	A8

Climatic Zone B - km's Breakdown	0 to 2	3 to 5	6 to 8	9 plus
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	B1	B2	B3	B4
24.9kv, 27.6kv, 44kv	B5	B6	B7	B8

Climatic Zone C - km's Breakdown	0 to 2	3 to 5	6 to 8	9 plus
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	C1	C2	C3	C4
24.9kv, 27.6kv, 44kv	C5	C6	C7	C8

Climatic Zone D - km's Breakdown	0 to 2	3 to 5	6 to 8	9 plus
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	D1	D2	D3	D4
24.9kv, 27.6kv, 44kv	D5	D6	D7	D8

Notes: Date across the top of the charts is the time since last brushed (ie. 0 to 2 = 0yrs to 2yrs since last brushed).

Defining plot locations

As noted above in the Sampling Methodology and Statistical Validity a minimum of 30 plots are required per key variable or sub-population. In the set-up of this project into the slot classes, at least 30 plots would then have to be completed per slot class.

Hydro One's above ground powerline network (44kv and less) was mapped using GIS into the 32 slot classes. The GIS system was then used to select random points in each slot class to define the start of the field survey for each plot.

Defining random sample plots: A random generator was used for each slot class. The computer electronically and in a non-biased fashion provided 70 points for each slot class.

- Points along the powerline infrastructure were selected. The only requirement per feeder was that plots were to be selected with a minimum distance of 2km's apart.
- The goal was to complete 35 plots in each slot class (we forecasted having to substitute plots for many reasons thus 70 random points were selected). This did not allow the field planners to use any of the 70 plots as they desired; systematically field planners worked through the list from 1 to 35 and then 36, 37, 38, etc. should plots require substituting.
- Substituting rules included the following;
    - Had to be approved by the ArborMetrics Solutions Foreman.
    - If the feeder being assessed was underbuilt.
    - Where plots should happen to overlap.
    - Database anomalies.
    - First Nations lands.
    - Unfeasible access (To be rarely used but economically feasible decisions also need to be made).

- In cases where once arriving on site the planner felt the defined slot class did not match the field.

Data Collection

Data Provided by Hydro One

- Feeder Data - feeder number, km, zone, date last worked, voltage class.
- Outage Data – feeder number, outage date, cause, SAIFI, SAIDI
- Cost/Work Data – feeder number, work units, cost

Data Collected by ArborMetrics during the field survey;
(A complete list and description of the field survey procedures can be seen in the appendices; ArborMetrics Solutions System Survey Essentials).
Each plot included the following:

- 1km minimum in length
- Data captured by span. Spans combined until 1km in length reached.

Key definitions:

	Definitions
Tree	>4" dbh Non-compatible
Brush	< 4" dbh Non-compatible
On ROW	5.0m centerline on all voltages except 44kv 6.0m centerline on 44kv
Off ROW	Outside the measurements above
Vegetation to be assessed	For ALL questions ONLY vegetation that will be/could be a threat or defect is to be considered, counted or measured. - Vegetation that will not grow or fall onto the conductor in the future is NOT assessed. - We are ONLY assessing non-compatible species. - Deemed compatible areas such as maintained hedges are not to be assessed.
Off ROW tree count	Trees that are currently tall enough to contact the powerline. All trees dead/dying/healthy etc. are included. Note trees that are leaning away and are not a concern are not to be counted.
Multi-stem Trees	Trees will simply be counted by the number of stems >4" dbh. Please note that if one stem is growing/leaning away from the conductor and pose no threat than it would not be counted.
Defect	Current growing defects: Currently within 12" of the primary 3 year growing defects: Estimate that within 3 years the vegetation will be within 12" 1-year hazard defect: Assessed falling risk of a tree is high in the next year. 3-year hazard defect: Assessed falling risk of a tress is high in the next 3 years.

Field Survey Data Collected;

- Vegetation Type: Clear, Conifer, Mixed wood, Deciduous
- First tree species of concern to the powerline.
- Second tree species of concern to the powerline.
- Third tree species of concern to the powerline.
- Access: Roadside, Inset, Backyard, XC
- Bump Sleeve Count: Physical count.
- Pole Type: Pole top, Three Phase, H Frame, Vertical
- Tree Population on ROW: Physical count.

- Tree Population on ROW Diameter: Average diameter in range classes.
- Tree Population on ROW Defects: Count of defects
- Tree Population on ROW 3 yr. Defects: Estimated, count of defects
- Tree Population off ROW: Physical count.
- Tree Population off ROW Diameter: Average diameter in range classes.
- Tree Population off ROW Defects: Count of defects
- Tree Population off ROW 3 yr. Defects: Estimated, Count of defects
- Hazard Defects: 0-1 yr. falling hazard tree risks.
- 3 yr. Hazard Defects: 1-3 yr. falling hazard tree risks.
- Overhang: Based on number of trees and amount of overhang.
- Brush population on ROW: Length X Width
- Brush population on ROW Density: Low to Heavy classes.
- Brush population on ROW Height: Average
- Brush population on ROW current defects: Count of defects
- Brush Population on ROW 3 yr. Defects: Estimated, count of defects

Conducting the Survey

In preparing to complete the field survey, six vegetation planners were decided on to meet the project goals including a deadline of early June 2017. A package outlining the survey procedures was constructed while the team was being assembled. The planners reviewed the survey procedures prior to the start-up and all had ArborMetrics Solutions general experience and knowledge. In the preparation phase an electronic GIS database was configured to collect the field data in ArborMetrics Solutions internal software named ArborLine.

<u>Field Team Assembled.</u>

ArborMetrics Solutions Vegetation Planners: Responsible for survey plot data collection.

ArborMetrics Solutions Foreman/Quality Assurance: Responsible for survey logistics and quality.

Hydro One Field Staff: Responsible for site safety, transportation of Vegetation planner, customer relations
Hydro One Foreman: Responsible for ensuring procedures and survey processes and being followed.

APPENDIX B – SLOT CLASS DISTRIBUTION

Corridor KM of Slot Classes by Zone and Voltage

Key breakdown of Hydro One Utility Powerline Infrastructure

CORRIDOR LENGTH

Climatic Zone A - km's Breakdown

	0 to 2	3 to 5	6 to 8	9 plus	
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	3,221	4,288	5,963	6,839	
	(A1)	(A2)	(A3)	(A4)	
24.9kv, 27.6kv, 44kv	4,827	3,465	322	335	
	(A5)	(A6)	(A7)	(A8)	
				Total:	29,261

Climatic Zone B - km's Breakdown

	0 to 2	3 to 5	6 to 8	9 plus	Total
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	4,355	4,477	4,535	7,477	
	(B1)	(B2)	(B3)	(B4)	
24.9kv, 27.6kv, 44kv	2,189	1,989	277	-	
	(B5)	(B6)	(B7)	(B8)	
Total					25,299

Climatic Zone C - km's Breakdown

	0 to 2	3 to 5	6 to 8	9 plus	Total
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	7,246	5,984	7,212	4,221	
	(C1)	(C2)	(C3)	(C4)	
24.9kv, 27.6kv, 44kv	2,253	2,120	39	72	
	(C5)	(C6)	(C7)	(C8)	
Total					29,128

Climatic Zone D - km's Breakdown

	0 to 2	3 to 5	6 to 8	9 plus	Total
4.16kv, 8.32, 12.5kv, 13.8kv, 22kv	2,859	2,491	1,967	1,997	
	(D1)	(D2)	(D3)	(D4)	
24.9kv, 27.6kv, 44kv	2,487	2,661	1,839	995	
	(D5)	(D6)	(D7)	(D8)	
Total					17,297

TOTAL Corridor km's:	100,985

Number of Sample Plots Surveyed for Each Slot Class

Key breakdown of Hydro One Utility Powerline Infrastructure

SURVEY PLOTS SUMMARY

Climatic Zone A

# of survey plots completed	35	31	42	36	
Km of corridor surveyed	35.9	33.2	45.0	37.9	
	(A1)	(A2)	(A3)	(A4)	
# of survey plots completed	36	36	37	35	
Km of corridor surveyed	38.2	38.1	38.5	36.7	
	(A5)	(A6)	(A7)	(A8)	
				Plots Surveyed	288
				Km's Surveyed	303.4

Climatic Zone B

# of survey plots completed	36	34	38	37	
Km of corridor surveyed	38.2	35.3	40.3	38.9	
	(B1)	(B2)	(B3)	(B4)	
# of survey plots completed	35	35	36	-	
Km of corridor surveyed	36.6	36.6	37.6	-	
	(B5)	(B6)	(B7)	(B8)	
				Plots Surveyed	251
				Km's Surveyed	263.5

Climatic Zone C

# of survey plots completed	32	38	46	36	
Km of corridor surveyed	33.2	39.8	47.9	37.3	
	(C1)	(C2)	(C3)	(C4)	
# of survey plots completed	35	37	33		
Km of corridor surveyed	36.4	38.3	34.2	-	
	(C5)	(C6)	(C7)	(C8)	
				Plots Surveyed	257
				Km's Surveyed	267.2

Climatic Zone D

# of survey plots completed	32	32	40	33	
Km of corridor surveyed	33.4	33.7	41.9	34.5	
	(D1)	(D2)	(D3)	(D4)	
# of survey plots completed	35	35	33	33	
Km of corridor surveyed	36.6	37.5	34.1	34.3	
	(D5)	(D6)	(D7)	(D8)	
				Plots Surveyed	273
				Km's Surveyed	286.0

TOTAL PLOTS SURVEYED:	1,069
TOTAL KM'S SURVEYED	1,120

APPENDIX C – SUPPLEMENTAL SURVEY RESULTS

Access Type – System Percentage

Access Type	km	Percentage
Back Lot	127	.1%
Inset from Road	6,099	6%
Roadside	87,870	87%
Cross Country	6,899	7%

***System KM Extrapolated**

Access km by Zone

Zone	Back Lot	Inset	Roadside	Cross Country
Zone A	31	1,265	27,479	487
Zone B	7	1,116	22,017	2,159
Zone C	52	2,682	23,244	3,144
Zone D	33	1,106	14,940	1,218

Tree Population

Zone	On-ROW	Off-ROW	Total	Per km
Zone A	1,163,884	1,093,974	2,257,858	77
Zone B	1,159739	1,786,023	2,945,762	116
Zone C	817,560	4,412,167	5,229,727	180
Zone D	401,559	2,319,491	2,721,091	157
Total	3,451,880	9,806,483	13,258,363	131

Note: 41% of spans surveyed had no trees present.

Brush Density - Extrapolated

Density	% of km	Hectares
None – no incompatible brush noted	53%	0
Ultra-Low - < 50 stems per span	28%	6,498
Very Low - < 50 – 250 stems per span	9%	26,823
Low - > 250 stems, easy to walk	6%	54,252
Medium – Clumpy, moderate effort to walk	<3%	67,606
Heavy – Dense, difficult to walk	<2%	63,729

Overhangs

Class	Spans Surveyed	Extrapolated
A (1-5) trees overhanging the ROW up to the conductor	543	47,000
B (6-10) trees overhanging the ROW up to the conductor	33	2,900
C (11-15) trees overhanging the ROW up to the conductor	9	800
F (1-5) trees overhanging the conductor	362	32,000
G (6-10) trees overhanging the conductor	44	3,900
H (11-15) trees overhanging the conductor	8	700
I (16-20) trees overhanging the conductor	2	170

Note: Less than 1% 44kV spans had overhangs present.

Top 10 Species (based on spans)

Species	% of spans
Maple (all)	22.5%
Poplar	14.7%
Spruce	13.4%
Pine (all)	10.0%
Cedar	9.7%
Ash	8.4%
Birch	3.2%
Oak	3.0%
Willow	3.0%
Elm	2.2%

Filed: 2017-12-21
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Attachment 3
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2021 Cost Allocation Model

EB-2017-0049

Sheet O1 Revenue to Cost Summary Worksheet -

Rate Base Assets		Total	1 UR	2 R1	3 R2	4 Seasonal	5 GSe	6 GSd	7 UGe	8 UGd	9 St Lgt	10 Sen Lgt	11 USL	12 DGen	13 ST	14 AUR	15 AUGe	16 AUGd	17 AR	18 AGSe	19 AGSd
crev	Distribution Revenue at Existing Rates	$1,582,235,723	$100,704,642	$337,959,393	$550,079,444	$116,938,615	$160,478,744	$147,963,022	$23,147,088	$30,585,303	$14,136,825	$3,805,212	$3,395,663	$5,712,491	$55,937,606	$5,508,610	$1,032,227	$1,383,942	$16,399,355	$3,747,248	$3,320,293
mi	Miscellaneous Revenue (mi)	$55,882,454	$5,222,741	$14,139,713	$17,531,755	$3,326,772	$5,231,035	$2,963,018	$905,245	$666,322	$440,665	$2,459,061	$133,994	$198,876	$1,355,497	$265,132	$40,871	$34,520	$740,971	$148,526	$77,740
		Miscellaneous Revenue Input equals Output				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Revenue at Existing Rates	$1,638,118,177	$105,927,382	$352,099,106	$567,611,199	$120,265,387	$165,709,779	$150,926,041	$24,052,333	$31,251,625	$14,577,490	$6,264,274	$3,529,657	$5,911,366	$57,293,102	$5,773,742	$1,073,098	$1,418,463	$17,140,326	$3,895,774	$3,398,033
	Factor required to recover deficiency (1 + D)	1.0267																			
	Distribution Revenue at Status Quo Rates	$1,624,550,523	$103,397,854	$346,997,670	$564,790,590	$120,065,983	$164,770,536	$151,920,097	$23,766,126	$31,403,266	$14,514,896	$3,906,978	$3,486,476	$5,865,264	$57,433,583	$5,655,931	$1,059,832	$1,420,954	$16,837,934	$3,847,464	$3,409,090
	Miscellaneous Revenue (mi)	$55,882,454	$5,222,741	$14,139,713	$17,531,755	$3,326,772	$5,231,035	$2,963,018	$905,245	$666,322	$440,665	$2,459,061	$133,994	$198,876	$1,355,497	$265,132	$40,871	$34,520	$740,971	$148,526	$77,740
	Total Revenue at Status Quo Rates	$1,680,432,976	$108,620,594	$361,137,383	$582,322,345	$123,392,755	$170,001,570	$154,883,116	$24,671,371	$32,069,588	$14,955,561	$6,366,039	$3,620,469	$6,064,139	$58,789,080	$5,921,063	$1,100,704	$1,455,474	$17,578,905	$3,995,990	$3,486,830
	Expenses																				
di	Distribution Costs (di)	$324,101,078	$15,121,178	$61,464,132	$131,142,265	$23,660,910	$32,280,335	$26,152,196	$3,947,618	$5,379,509	$3,714,022	$1,313,876	$694,837	$170,375	$11,960,624	$1,113,873	$217,669	$231,905	$3,914,134	$860,710	$760,909
cu	Customer Related Costs (cu)	$118,872,405	$17,820,370	$36,521,560	$30,135,148	$7,490,787	$11,660,183	$3,673,881	$2,401,599	$939,489	$850,466	$312,972	$479,549	$781,380	$1,483,830	$990,150	$155,982	$49,672	$2,529,476	$486,762	$109,147
ad	General and Administration (ad)	$167,217,070	$12,017,182	$36,147,355	$60,230,547	$11,574,907	$16,454,999	$12,118,409	$2,373,294	$2,606,442	$1,692,719	$600,957	$427,872	$1,044,928	$5,581,907	$767,634	$139,189	$197,548	$2,368,250	$500,134	$372,797
dep	Depreciation and Amortization (dep)	$446,076,294	$24,433,612	$83,227,081	$156,769,825	$29,402,219	$46,125,893	$52,158,503	$6,806,049	$11,097,028	$3,794,562	$1,657,166	$658,149	$1,015,093	$17,475,675	$1,575,648	$491,136	$779,211	$5,388,124	$1,399,257	$1,822,062
INPUT	PILs (INPUT)	$72,364,565	$3,480,949	$13,076,488	$26,521,444	$4,695,412	$7,573,082	$8,376,196	$1,065,110	$1,740,995	$671,325	$222,545	$120,515	$78,816	$3,164,220	$222,906	$59,371	$70,098	$799,578	$201,959	$223,555
INT	Interest	$224,695,067	$10,808,496	$40,603,056	$82,350,219	$14,579,455	$23,514,744	$26,008,447	$3,307,211	$5,405,864	$2,084,494	$691,012	$374,204	$244,726	$9,825,038	$692,133	$184,350	$217,657	$2,482,724	$627,090	$694,147
	Total Expenses	$1,353,326,478	$83,681,789	$271,039,672	$487,149,449	$91,403,691	$137,609,236	$128,487,633	$19,900,882	$27,169,327	$12,807,590	$4,798,528	$2,755,126	$3,335,317	$49,491,293	$5,362,343	$1,247,697	$1,546,091	$17,482,285	$4,075,912	$3,982,616
	Direct Allocation	$11,174,701	$0	$0	$0	$0	$0	$2,413,988	$0	$736,552	$0	$898,092	$0	$3,735,618	$2,748,938	$0	$0	$456,187	$0	$0	$185,326
NI	Allocated Net Income (NI)	$315,931,797	$15,197,253	$57,089,800	$115,788,268	$20,499,397	$33,062,832	$36,569,096	$4,650,094	$7,600,898	$2,930,897	$971,595	$526,148	$344,096	$13,814,463	$973,171	$259,205	$306,036	$3,490,826	$881,718	$976,004
	Revenue Requirement (includes NI)	$1,680,432,976	$98,879,041	$328,129,471	$602,937,718	$111,903,088	$170,672,067	$167,470,717	$24,550,976	$35,506,777	$15,738,486	$6,668,215	$3,281,275	$7,415,031	$66,054,695	$6,335,515	$1,506,902	$2,308,314	$20,973,111	$4,957,631	$5,143,946
		Revenue Requirement Input equals Output																			
	Rate Base Calculation																				
	Net Assets																				
dp	Distribution Plant - Gross	$13,156,156,067	$655,190,527	$2,387,593,637	$4,723,483,078	$864,593,067	$1,321,080,445	$1,464,966,614	$187,237,154	$306,051,482	$115,855,816	$38,447,389	$20,778,044	$17,930,046	$502,301,942	$79,757,736	$28,645,613	$60,356,495	$226,150,961	$53,822,926	$101,913,096
gp	General Plant - Gross	$1,496,735,388	$71,573,219	$268,822,522	$544,196,821	$97,529,491	$153,581,420	$170,963,119	$21,570,068	$35,557,715	$13,707,040	$19,717,864	$2,472,594	$1,761,866	$62,972,141	$4,581,837	$1,204,081	$1,425,553	$16,462,184	$4,086,947	$4,548,905
accum dep	Accumulated Depreciation	($5,174,483,179)	($276,569,870)	($965,528,784)	($1,844,694,618)	($348,664,339)	($508,638,325)	($560,575,709)	($73,131,999)	($117,952,000)	($43,345,897)	($23,674,904)	($7,698,080)	($8,609,814)	($196,945,172)	($28,936,867)	($9,937,113)	($19,934,781)	($84,888,843)	($19,951,121)	($34,804,943)
co	Capital Contribution	($896,478,209)	($44,023,555)	($165,094,172)	($328,846,205)	($65,155,170)	($83,286,507)	($98,532,254)	($11,536,460)	($20,614,574)	($7,925,700)	($3,292,280)	($1,492,733)	($1,824,702)	($27,780,391)	($5,567,456)	($1,788,060)	($3,901,326)	($15,918,802)	($3,265,626)	($6,632,236)
	Total Net Plant	$8,581,930,067	$406,170,322	$1,525,793,203	$3,094,139,076	$548,303,048	$882,737,032	$976,821,769	$124,138,763	$203,042,623	$78,291,260	$31,198,069	$14,059,826	$9,257,396	$340,548,519	$49,835,251	$18,124,521	$37,945,941	$141,805,500	$34,693,126	$65,024,822
	Directly Allocated Net Fixed Assets																				
COP	Cost of Power (COP)	$4,279,279,726	$373,935,334	$895,696,737	$797,465,237	$109,096,386	$363,509,620	$414,719,835	$106,124,886	$188,080,061	$23,932,584	$3,711,437	$4,719,497	$3,663,290	$831,554,126	$16,721,261	$7,798,829	$25,634,178	$51,754,337	$18,650,748	$42,511,345
	OM&A Expenses	$610,190,552	$44,958,731	$134,133,047	$221,507,961	$42,726,604	$60,395,517	$41,944,486	$8,722,512	$8,925,440	$6,257,208	$2,227,805	$1,602,259	$1,996,683	$19,026,361	$2,871,657	$512,840	$479,125	$8,811,860	$1,847,606	$1,242,852
	Directly Allocated Expenses	$11,174,701	$0	$0	$0	$0	$0	$2,413,988	$0	$736,552	$0	$898,092	$0	$3,735,618	$2,748,938	$0	$0	$456,187	$0	$0	$185,326
	Subtotal	$4,900,644,979	$418,894,065	$1,029,829,784	$1,018,973,198	$151,822,991	$423,905,137	$459,078,309	$114,847,398	$197,742,052	$30,189,792	$6,837,334	$6,321,756	$9,395,590	$853,329,424	$19,592,918	$8,311,669	$26,569,489	$60,566,196	$20,498,354	$43,939,524
	Working Capital	$384,364,096	$32,854,418	$80,770,918	$79,919,422	$11,907,679	$33,247,443	$36,006,122	$9,007,634	$15,509,172	$2,367,825	$536,261	$495,824	$736,909	$66,927,760	$1,536,699	$651,895	$2,083,880	$4,750,287	$1,607,713	$3,446,235
	Total Rate Base	$8,966,294,163	$439,024,740	$1,606,564,121	$3,174,058,498	$560,210,727	$915,984,475	$1,012,827,891	$133,146,397	$218,551,795	$80,659,085	$31,734,330	$14,555,649	$9,994,305	$407,476,280	$51,371,950	$18,776,416	$40,029,821	$146,555,787	$36,300,839	$68,471,057
		Rate Base Input Does Not Equal Output																			
	Equity Component of Rate Base	$3,586,517,665	$175,609,896	$642,625,648	$1,269,623,399	$224,084,291	$366,393,790	$405,131,156	$53,258,559	$87,420,718	$32,263,634	$12,693,732	$5,822,260	$3,997,722	$162,990,512	$20,548,780	$7,510,566	$16,011,928	$58,622,315	$14,520,336	$27,388,423
	Net Income on Allocated Assets	$315,931,797	$24,938,806	$90,097,711	$95,172,896	$31,989,064	$32,392,335	$23,981,495	$4,770,489	$4,163,709	$2,147,971	$669,419	$865,343	($1,006,796)	$6,548,848	$558,719	($146,994)	($546,804)	$96,620	($79,923)	($681,112)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$315,931,797	$24,938,806	$90,097,711	$95,172,896	$31,989,064	$32,392,335	$23,981,495	$4,770,489	$4,163,709	$2,147,971	$669,419	$865,343	($1,006,796)	$6,548,848	$558,719	($146,994)	($546,804)	$96,620	($79,923)	($681,112)
	RATIOS ANALYSIS																				
	REVENUE TO EXPENSES STATUS QUO%	100.00%	1.10	1.10	0.97	1.10	1.00	0.92	1.00	0.90	0.95	0.95	1.10	0.82	0.89	0.93	0.73	0.63	0.84	0.81	0.68
	EXISTING REVENUE MINUS ALLOCATED COSTS	($42,314,799)	$7,048,341	$23,969,635	($35,326,519)	$8,362,299	($4,962,289)	($16,544,677)	($498,643)	($4,255,152)	($1,160,996)	($403,941)	$248,382	($1,503,664)	($8,761,592)	($561,772)	($433,804)	($889,852)	($3,832,785)	($1,061,856)	($1,745,913)
		Deficiency Input equals Output			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$9,741,553	$33,007,912	($20,615,373)	$11,489,667	($670,497)	($12,587,601)	$120,395	($3,437,189)	($782,925)	($302,176)	$339,194	($1,350,891)	($7,265,615)	($414,452)	($406,198)	($852,840)	($3,394,206)	($961,641)	($1,657,116)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.81%	14.20%	14.02%	7.50%	14.28%	8.84%	5.92%	8.96%	4.76%	6.66%	5.27%	14.86%	-25.18%	4.02%	2.72%	-1.96%	-3.41%	0.16%	-0.55%	-2.49%

Total Gross Plant including USoAs 1600s, 1700s and 2040	$14,945,253,151	($748,926,957)	$748,926,957.47	5.0%
Total Accumulated Depreciation including USoAs 1600s, 1700s and 2040	($5,397,912,261)			
Total Capital Contributions	($896,505,374)			
Total Net Plant	$8,650,835,515			
Working Captial	$384,364,096			
Total Rate Base	$9,035,199,611			
Rate Base from I3 TB Data Sheet	$9,036,518,375			
	Rate Base Input Equals Output			

2021 Rate Design Including 6th Year of Phase-in to All-Fixed Rates

	Number of Customers	GWh	kWs	Revenue	Alloc Cost		Misc Rev	Revenue from Rates	2020 R/C Ratio	R/C Ratio from the CAM	Target 2021 R/C Ratio	Total rev to be collected	Shifted Rev
				(A)	(B)	(%)	(C)	(D=A-C)	(E)	(F=A/B)	(G)	(H=BxG)	(I=H-A)
UR	234,088	2,075		108,620,594	98,879,041	5.88%	$ 5,222,741	$ 103,397,854	1.07	1.10	1.10	$ 108,582,111	$ (38,484)
R1	457,608	4,971		361,137,383	328,129,471	19.53%	$ 14,139,713	$ 346,997,670	1.09	1.10	1.10	$ 360,329,045	$ (808,338)
R2	333,473	4,426		582,322,345	602,937,718	35.88%	$ 17,531,755	$ 564,790,590	0.95	0.97	0.97	$ 582,322,345	$ -
Seasonal	150,445	605		123,392,755	111,903,088	6.66%	$ 3,326,772	$ 120,065,983	1.08	1.10	1.10	$ 122,884,216	$ (508,539)
GSe	88,435	2,018		170,001,570	170,672,067	10.16%	$ 5,231,035	$ 164,770,536	0.99	1.00	1.00	$ 170,001,570	$ -
GSd	5,563	2,302	7,887,971	154,883,116	167,470,717	9.97%	$ 2,963,018	$ 151,920,097	0.96	0.92	0.92	$ 154,883,116	$ -
UGe	18,380	589		24,671,371	24,550,976	1.46%	$ 905,245	$ 23,766,126	1.01	1.00	1.00	$ 24,671,371	$ -
UGd	1,772	1,044	2,771,740	32,069,588	35,506,777	2.11%	$ 666,322	$ 31,403,266	0.94	0.90	0.90	$ 32,069,588	$ -
St Lgt	5,445	133		14,955,561	15,738,486	0.94%	$ 440,665	$ 14,514,896	0.94	0.95	0.95	$ 14,955,561	$ -
Sen Lgt	23,719	21		6,366,039	6,668,215	0.40%	$ 2,459,061	$ 3,906,978	1.03	0.95	0.95	$ 6,366,039	$ -
USL	5,944	26		3,620,469	3,281,275	0.20%	$ 133,994	$ 3,486,476	1.09	1.10	1.10	$ 3,603,269	$ (17,201)
DGen	1,508	20	204,487	6,064,139	7,415,031	0.44%	$ 198,876	$ 5,865,264	0.81	0.82	0.82	$ 6,064,139	$ -
ST	825	15,132	29,457,615	58,789,080	66,054,695	3.93%	$ 1,355,497	$ 57,433,583	0.97	0.89	0.89	$ 58,789,080	$ -
AUR	15,312	93		5,921,063	6,335,515	0.38%	$ 265,132	$ 5,655,931	-	0.93	0.93	$ 5,921,063	$ -
AUGe	1,339	43		1,100,704	1,506,902	0.09%	$ 40,871	$ 1,059,832	-	0.73	0.80	$ 1,205,521	$ 104,818
AUGd	194	142	410,749	1,455,474	2,308,314	0.14%	$ 34,520	$ 1,420,954	-	0.63	0.80	$ 1,846,651	$ 391,177
AR	37,769	287		17,578,905	20,973,111	1.25%		$ 16,837,934	-	0.84	0.85	$ 17,827,144	$ 248,239
AGSe	4,339	104		3,995,990	4,957,631	0.30%	$ 148,526	$ 3,847,464	-	0.81	0.81	$ 3,995,990	$ -
AGSd	365	236	663,644	3,486,830	5,143,946	0.31%	$ 77,740	$ 3,409,090	-	0.68	0.80	$ 4,115,157	$ 628,327
	1,386,522	**34,267**	**41,396,206**	**1,680,432,976**	**1,680,432,976**	**100%**	**55,882,454**	**1,624,550,523**				**$ 1,680,432,976**	**$ (0)**

Note 1: ST rates are listed in Attachment 2b

2021 Rate Design Including 6th Year of Phase-in to All-Fixed Rates

	% Change in revenue from rates	Fixed Charge ($/month)	Revenue from Fixed Charge	Fixed Rev %	Revenue from Volumetric Charge	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)	CSTA Rate Adders ($/kW)	Hopper Foundry Rate Adder ($/kW)	Total Volumetric Charge ($/kW)
	(J=I/D)		(K)		(L=H-C-K)					
UR	0.0%	$ 36.80	$ 103,359,370	100%	$ -	$ -				
R1	-0.2%	$ 52.39	$ 287,676,749	83%	$ 58,512,584	$ 0.0118				
R2	0.0%	$ 118.85	$ 475,610,380	84%	$ 89,180,210	$ 0.0201				
Seasonal	-0.4%	$ 55.44	$ 100,090,795	84%	$ 19,466,650	$ 0.0322				
GSe	0.0%	$ 31.38	$ 33,302,114	20%	$ 131,468,422	$ 0.0652				
GSd	0.0%	$ 107.59	$ 7,182,325	5%	$ 144,737,773		$ 18.3492	$ 0.0824	$ 0.0086	$ 18.4402
UGe	0.0%	$ 25.55	$ 5,635,169	24%	$ 18,130,957	$ 0.0308				
UGd	0.0%	$ 106.68	$ 2,268,719	7%	$ 29,134,547		$ 10.5113	$ 0.0824		$ 10.5937
St Lgt	0.0%	$ 4.77	$ 311,698	2%	$ 14,203,197	$ 0.1069				
Sen Lgt	0.0%	$ 3.72	$ 1,057,967	27%	$ 2,849,011	$ 0.1383				
USL	-0.5%	$ 37.49	$ 2,674,049	77%	$ 795,226	$ 0.0304				
DGen	0.0%	$ 196.16	$ 3,548,958	61%	$ 2,316,306		$ 11.3274	$ 0.0824		$ 11.4098
ST	0.0%	*(Note 1)*	$ 10,745,952	19%	$ 46,687,631		*(Note 1)*			*(Note 1)*
AUR	0.0%	$ 30.78	$ 5,655,931	100%	$ -					
AUGe	9.9%	$ 28.42	$ 456,514	39%	$ 708,136	$ 0.0164				
AUGd	27.5%	$ 183.26	$ 425,757	23%	$ 1,386,374		$ 3.3752	$ 0.0824		$ 3.4576
AR	1.5%	$ 37.70	$ 17,086,173	100%	$ -					
AGSe	0.0%	$ 38.65	$ 2,012,419	52%	$ 1,835,045	$ 0.0177				
AGSd	18.4%	$ 194.68	$ 852,260	21%	$ 3,185,156		$ 4.7995	$ 0.0824		$ 4.8819
			$ 1,059,953,299		**$ 564,597,224**					
				Rates Rev	**$ 1,624,550,523**					
				Misc Rev	**$ 55,882,454**					
				Total Rev Req	**$ 1,680,432,976**					

Note 1: ST rates

Rate Class	2020 Current Fixed Charge	2021 All-Fixed Charge	Phase-in Period (Remaining Years)	Annual Increase in Fixed Charge	2021 Proposed Fixed Charge
R1	$ 47.06	$ 63.04	3	$ 5.33	$ 52.39
R2	$ 107.71	$ 141.14	3	$ 11.14	$ 118.85
Seasonal	$ 50.05	$ 66.22	3	$ 5.39	$ 55.44

2021 Sub-Transmission (ST) Rates

	2021			
	Billing Quantity (Annual)	Rates		Revenue Generated (Annual)
HVDS-high cost allocation	988,107	1.8773	$/kW	$ 1,854,973
HVDS-low cost allocation	41,200	3.6780	$/kW	$ 151,532
LVDS-low cost allocation	776,996	1.8007	$/kW	$ 1,399,137
Specific ST lines	830	720.1311	$/kM	$ 597,746
Fixed Rate	9,896	564.1200	$	$ 5,582,451
Meter Charge	7,311	706.2500	$	$ 5,163,477
Total revenue generated through other delivery charges:				$ 14,749,318
Revenue to be collected by ST (adjusted for change in revenue from Rates target R/C Ratio, if applicable)				$ 57,433,583
ST Common Line Revenue Requirement (Annual)				$ 42,684,265
ST Common Line Charge Determinant (Annual)	29,457,615			
ST Common Line Charge ($/kW)		**$ 1.4490**		

2022 Rate Design Including 7th Year of Phase-in to All-Fixed Rates

		Number of Customers	GWh	kWs	Revenue - with 2021 Rates and 2022 Charge Determinants	2021 Revenue	Revenue	Alloc Cost	Misc Rev	Revenue from Rates	2021 R/C Ratio	R/C Ratio
					(Y)	(Z)	($A=Y*X_{RevReq}$)	($B=B_{2018}*X_{AllocCost}$)	($C=C_{2018}*X_{MiscRev}$)	(D=A-C)	(E)	(F=A/B)
UR		236,737	2,090	-	$ 109,800,165.37	$ 108,582,110.67	$ 112,551,536	$ 101,690,674	$ 5,257,321	$ 107,294,215	1.10	1.11
R1		461,272	4,998	-	$ 363,050,284.74	$ 360,329,045.15	$ 372,147,592	$ 337,459,855	$ 14,233,333	$ 357,914,259	1.10	1.10
R2		335,223	4,408	-	$ 584,568,682.70	$ 582,322,344.86	$ 599,216,794	$ 620,082,293	$ 17,647,834	$ 581,568,959	0.97	0.97
Seasonal		150,701	600	-	$ 122,899,818.55	$ 122,884,216.06	$ 125,979,440	$ 115,085,060	$ 3,348,798	$ 122,630,641	1.10	1.09
GSe		88,515	1,999	-	$ 168,890,629.95	$ 170,001,570.28	$ 173,122,688	$ 175,525,139	$ 5,265,670	$ 167,857,018	1.00	0.99
GSd		5,612	2,297	7,871,666	$ 154,666,673.09	$ 154,883,115.84	$ 158,542,308	$ 172,232,759	$ 2,982,637	$ 155,559,671	0.92	0.92
UGe		18,501	589	-	$ 24,701,304.92	$ 24,671,371.14	$ 25,320,270	$ 25,249,085	$ 911,239	$ 24,409,031	1.00	1.00
UGd		1,783	1,044	2,764,065	$ 32,007,481.34	$ 32,069,588.11	$ 32,809,524	$ 36,516,415	$ 670,734	$ 32,138,790	0.90	0.90
St Lgt		5,481	133	-	$ 15,024,934.83	$ 14,955,560.93	$ 15,401,429	$ 16,186,011	$ 443,583	$ 14,957,846	0.95	0.95
Sen Lgt		23,605	20	-	$ 6,363,676.31	$ 6,366,039.20	$ 6,523,137	$ 6,857,826	$ 2,475,343	$ 4,047,794	0.95	0.95
USL		5,975	26	-	$ 3,624,369.92	$ 3,603,268.61	$ 3,715,189	$ 3,374,578	$ 134,881	$ 3,580,308	1.10	1.10
DGen		1,608	21	210,569	$ 6,371,578.41	$ 6,064,139.46	$ 6,531,237	$ 7,625,878	$ 200,192	$ 6,331,045	0.82	0.86
ST		828	15,149	29,499,182	$ 58,907,180.26	$ 58,789,079.69	$ 60,383,275	$ 67,932,964	$ 1,364,471	$ 59,018,804	0.89	0.89
AUR		15,467	92	-	$ 5,979,682.02	$ 5,921,062.63	$ 6,129,521	$ 6,515,665	$ 266,887	$ 5,862,634	0.93	0.94
AUGe		1,352	44	-	$ 1,216,980.05	$ 1,205,521.49	$ 1,247,475	$ 1,549,751	$ 41,142	$ 1,206,333	0.80	0.80
AUGd		194	143	411,710	$ 1,850,335.23	$ 1,846,651.26	$ 1,896,701	$ 2,373,951	$ 34,749	$ 1,861,952	0.80	0.80
AR		38,018	284	-	$ 17,945,176.59	$ 17,827,144.41	$ 18,394,846	$ 21,569,483	$ 745,877	$ 17,648,969	0.85	0.85
AGSe		4,337	102	-	$ 3,974,396.75	$ 3,995,989.55	$ 4,073,987	$ 5,098,601	$ 149,509	$ 3,924,478	0.81	0.80
AGSd		371	236	662,981	$ 4,125,867.59	$ 4,115,156.73	$ 4,229,253	$ 5,290,214	$ 78,255	$ 4,150,999	0.80	0.80
		1,395,578	**34,276**	**41,420,173**	**1,685,969,219**	**1,680,432,976**	**1,728,216,204**	**1,728,216,204**	**56,252,456**	**1,671,963,747**		

Note 1: ST rates are listed in Attachment 3b

2022 Adjustments (from 2021 Revenue Requirement) by Rate Class

	2021	2022	%
Revenue Requirement**	$ 1,685,969,219	$ 1,728,216,204	102.51%
Alloc Cost	$ 1,680,432,976	$ 1,728,216,204	102.84%
Misc Revenue	$ 55,882,454	$ 56,252,456	100.66%

** 2021: Revenue with 2021 rates and 2022 charge determinants
2022: 2022 Revenue before rate design adjustments

2022 Rate Design Including 7th Year of Phase-in to All-Fixed Rates

Filed: 2017-12-21
EB-2017-0049
Exhibit Q-1-1
Attachment 5

	Target 2022 R/C Ratio	Total rev to be collected	Shifted Rev	% Change in revenue from rates	Fixed Charge ($/month)	Revenue from Fixed Charge	Fixed Rev %	Revenue from Volumetric Charge	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)	CSTA Rate Adders ($/kW)	Hopper Foundry Rate Adder ($/kW)	Total Volumetric Charge ($/kW)
	(G)	(H=BxG)	(I=H-A)	(J=I/D)		(K)		(L=H-C-K)					
UR	1.11	$ 112,551,536	$ -	0.0%	$ 37.77	$ 107,294,215	100%	$ -	$ -				
R1	1.10	$ 372,147,592	$ -	0.0%	$ 58.53	$ 323,953,382	91%	$ 33,960,877	$ 0.0068				
R2	0.97	$ 599,216,794	$ -	0.0%	$ 131.71	$ 529,831,652	91%	$ 51,737,308	$ 0.0117				
Seasonal	1.09	$ 125,979,440	$ -	0.0%	$ 61.63	$ 111,444,371	91%	$ 11,186,270	$ 0.0186				
GSe	0.99	$ 173,122,688	$ -	0.0%	$ 31.94	$ 33,925,929	20%	$ 133,931,089	$ 0.0670				
GSd	0.92	$ 158,542,308	$ -	0.0%	$ 109.21	$ 7,354,393	5%	$ 148,205,278		$ 18.8277	$ 0.0827	$ 0.0089	$ 18.9193
UGe	1.00	$ 25,320,270	$ -	0.0%	$ 26.07	$ 5,787,608	24%	$ 18,621,423	$ 0.0316				
UGd	0.90	$ 32,809,524	$ -	0.0%	$ 108.50	$ 2,321,857	7%	$ 29,816,934		$ 10.7874	$ 0.0827		$ 10.8701
St Lgt	0.95	$ 15,401,429	$ -	0.0%	$ 4.88	$ 321,211	2%	$ 14,636,636	$ 0.1097				
Sen Lgt	0.95	$ 6,523,137	$ -	0.0%	$ 3.87	$ 1,096,098	27%	$ 2,951,696	$ 0.1440				
USL	1.10	$ 3,715,189	$ -	0.0%	$ 38.49	$ 2,759,632	77%	$ 820,677	$ 0.0311				
DGen	0.86	$ 6,531,237	$ -	0.0%	$ 196.16	$ 3,786,184	60%	$ 2,544,861		$ 12.0856	$ 0.0827		$ 12.1683
ST	0.89	$ 60,383,275	$ -	0.0%	*(Note 1)*	$ 11,042,551	19%	$ 47,976,253		*(Note 1)*			*(Note 1)*
AUR	0.94	$ 6,129,521	$ -	0.0%	$ 31.59	$ 5,862,634	100%	$ -	$ -				
AUGe	0.80	$ 1,247,475	$ -	0.0%	$ 29.14	$ 472,853	39%	$ 733,480	$ 0.0168				
AUGd	0.80	$ 1,896,701	$ -	0.0%	$ 188.20	$ 437,463	23%	$ 1,424,489		$ 3.4599	$ 0.0827		$ 3.5426
AR	0.85	$ 18,394,846	$ -	0.0%	$ 38.69	$ 17,648,969	100%	$ -	$ -				
AGSe	0.80	$ 4,073,987	$ -	0.0%	$ 39.44	$ 2,052,701	52%	$ 1,871,777	$ 0.0183				
AGSd	0.80	$ 4,229,253	$ -	0.0%	$ 197.06	$ 876,236	21%	$ 3,274,762		$ 4.9395	$ 0.0827		$ 5.0222
		$ 1,728,216,204	**0**			**$ 1,168,269,938**		**$ 503,693,809**					

Note 1: ST rates a

Rates Rev	**$ 1,671,963,747**
Misc Rev	**$ 56,252,456**
Total Rev Req	**$ 1,728,216,204**

Rate Class	2021 Current Fixed Charge	2022 All-Fixed Charge	Phase-in Period (Remaining Years)	Annual Increase in Fixed Charge	2022 Proposed Fixed Charge
R1	$ 52.39	$ 64.66	2	$ 6.14	$ 58.53
R2	$ 118.85	$ 144.57	2	$ 12.86	$ 131.71
Seasonal	$ 55.44	$ 67.81	2	$ 6.19	$ 61.63

2022 Sub-Transmission (ST) Rates

	2022			
Minus	Billing Quantity (Annual)	Rates		Revenue Generated (Annual)
HVDS-high cost allocation	990,871	1.8773	$/kW	$ 1,860,162
HVDS-low cost allocation	41,000	3.6769	$/kW	$ 150,751
LVDS-low cost allocation	777,489	1.7996	$/kW	$ 1,399,170
Specific ST lines	830	720.1311	$/kM	$ 597,746
Plus:				
Fixed Rate	9,936	577.3700	$	$ 5,736,586
Meter Charge	7,341	722.8300	$	$ 5,305,983
Total revenue generated through other delivery charges:				$ 15,050,398
Revenue to be collected by ST (adjusted for change in revenue from Rates target R/C Ratio, if applicable)				$ 59,018,804
ST Common Line Revenue Requirement (Annual)				$ 43,968,405
ST Common Line Charge Determinant (Annual)	29,499,182			
ST Common Line Charge ($/kW)		**$ 1.4905**		

Average increase for a rebasing year	
2015/2014 Average Increase for Residential class	7.5%
2015/2014 Average Increase for GS<50kW class	6.9%
2016/2015 Average Increase for Residential class	8.1%
2016/2015 Average Increase for GS<50kW class	6.6%
2017/2016 Average Increase for Residential class	4.1%
2017/2016 Average Increase for GS<50kW class	4.8%
Average Increase	**6.3%**

Growth assumptions used for each year

Year	Norfolk (2012 Rebasing)				Haldimand (2014 Rebasing)				Woodstock (2011 Rebasing)			
	Price Cap IR			CoS	Price Cap IR			CoS	Price Cap IR			CoS
	Inflation Factor	Stretch Factor	Final Adjustment Factor		Inflation Factor	Stretch Factor	Final Adjustment Factor		Inflation Factor	Stretch Factor	Final Adjustment Factor	
2014	1.70%	0.30%	1.40%		N/A				N/A			
2015	1.60%	0.30%	1.30%		1.60%	0.15%	1.45%					6.30%
2016				6.30%	2.10%	0.15%	1.95%		2.10%	0.60%	1.50%	
2017	1.90%	0.30%	1.60%		1.90%	0.15%	1.75%		1.90%	0.45%	1.45%	
2018	1.20%	0.30%	0.90%					6.30%	1.20%	0.45%	0.75%	
2019	1.20%	0.30%	0.90%		1.20%	0.15%	1.05%		1.20%	0.45%	0.75%	
2020	1.20%	0.30%	0.90%		1.20%	0.15%	1.05%					6.30%
2021				6.30%	1.20%	0.15%	1.05%		1.20%	0.45%	0.75%	

2015/2014 Average Increase for Residential Class

Residential	MFC 2015	VC 2015	MFC 2014	VC 2014	TB 2015	TB 2014	$ Change	% Change
Festival Hydro Inc.	16.27	12.30	15.18	12.68	28.57	27.86	0.72	2.57%
Hearst Power Distribution Company Limited	11.93	9.45	9.19	12.00	21.38	21.19	0.19	0.90%
Horizon Utilities Corporation	15.72	11.63	14.92	11.03	27.35	25.95	1.41	5.42%
Hydro One Brampton Networks Inc.	11.07	11.63	10.10	11.03	22.70	21.13	1.58	7.46%
Niagara Peninsula Energy Inc.	18.43	13.88	16.06	12.08	32.31	28.14	4.18	14.84%
North Bay Hydro Distribution Limited	15.71	10.58	14.64	9.83	26.29	24.47	1.82	7.44%
St. Thomas Energy Inc.	14.21	12.60	11.53	12.00	26.81	23.53	3.28	13.94%

Source of data: 2014 and 2015 Rates Database published by the OEB

2015/2014 Average Increase for Residential Class (excluding Algoma) **7.5%**

2015/2014 Average Increase for General Service<50 kW Class

General Service < 50kW	MFC 2015	VC 2015	MFC 2014	VC 2014	TB 2015	TB 2014	$ Change	% Change
Festival Hydro Inc.	30.66	30.40	29.44	29.80	61.06	59.24	1.82	3.07%
Hearst Power Distribution Company Limited	18.30	12.40	19.76	13.40	30.70	33.16	-2.46	-7.42%
Horizon Utilities Corporation	39.14	20.20	33.21	17.20	59.34	50.41	8.93	17.71%
Hydro One Brampton Networks Inc.	24.39	32.20	18.23	32.00	56.59	50.23	6.36	12.66%
Niagara Peninsula Energy Inc.	37.76	27.60	37.79	27.60	65.36	65.39	-0.03	-0.05%
North Bay Hydro Distribution Limited	23.27	35.80	21.69	33.40	59.07	55.09	3.98	7.22%
St. Thomas Energy Inc.	23.20	31.60	17.47	30.20	54.80	47.67	7.13	14.96%

Source of data: 2014 and 2015 Rates Database published by the OEB

2015/2014 Average Increase for GS<50 kW Class (excluding Algoma) 6.9%

2016/2015 Average Increase for Residential Class

Residential	MFC 2016	VC 2016	MFC 2015	VC 2015	TB 2016	TB 2015	$ Change	% Change
Entegrus Powerlines Inc. - Chatham-Kent	18.98	5.78	18.98	6.60	24.76	25.58	-0.82	-3.00%
Grimsby Power Inc.	19.55	7.43	15.69	9.08	26.98	24.77	2.21	9.00%
Guelph Hydro Electric Systems Inc.	18.93	10.80	14.49	13.20	29.73	27.69	2.04	7.00%
Halton Hills Hydro Inc.	17.04	7.50	12.72	9.00	24.54	21.72	2.82	13.00%
Horizon Utilities Corporation	18.8	9.08	15.72	11.63	27.88	27.35	0.53	2.00%
Hydro Ottawa Limited	12.96	14.48	9.67	17.55	27.44	27.22	0.22	1.00%
Kingston Hydro Corporation	13.98	10.43	12.56	11.55	24.41	24.11	0.30	1.00%
Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkhill	18.98	5.78	14.43	10.95	24.76	25.38	-0.62	-2.00%
Entegrus Powerlines Inc. - Dutton	18.98	5.78	13.44	9.53	24.76	22.97	1.79	8.00%
Entegrus Powerlines Inc. - Newbury	18.98	5.78	12.52	9.45	24.76	21.97	2.79	13.00%
Milton Hydro Distribution inc.	18.61	8.25	15.43	10.80	26.86	26.23	0.63	2.00%
Oshawa PUC Networks Inc.	11.21	10.65	8.47	9.00	21.86	17.47	4.39	25.00%
Ottawa River Power Corporation	14.02	9.68	10.99	11.25	23.70	22.24	1.46	7.00%
PowerStream Inc. - Barrie	12.9	10.73	12.67	10.50	23.63	23.17	0.45	2.00%
Toronto Hydro-Electric System Limited	22.78	14.10	18.63	11.54	36.88	30.17	6.72	22.00%
Wasaga Distribution Inc.	14.91	8.85	11.57	10.80	23.76	22.37	1.39	6.00%
Waterloo North Hydro Inc.	19.71	11.55	15.2	14.40	31.26	29.60	1.66	6.00%
Wellington North Power Inc.	23.97	11.48	18.49	13.88	35.45	32.37	3.08	10.00%

Source of data: EB-2016-0055 (Algoma Power Inc. 2017 Rates Application). Hydro One received the detailed table above from Algoma Power Inc. (Algoma Power Inc. received this table from OEB staff). The table was compiled by OEB Staff and was used to determine the 2017 Algoma Power Inc. RRRP adjustment factor (see OEB Decision and Rate Order, issued on December 8, 2016, page 1).

2016/2015 Average Increase for Residential Class (Entegrus was excluded because rate increases are distorted by the impact of harmonization) 8.1%

2016/2015 Average Increase for General Service<50 kW Class

General Service < 50kW	MFC 2016	VC 2016	MFC 2015	VC 2015	TB 2016	TB 2015	$ Change	% Change
Entegrus Powerlines Inc. - Chatham-Kent	30	19.80	34.84	23.6	49.80	58.44	-8.64	-14.78%
Grimsby Power Inc.	24.32	37.40	26.67	26.2	61.72	52.87	8.85	16.74%
Guelph Hydro Electric Systems Inc.	16.33	27.40	15.57	26.2	43.73	41.77	1.96	4.69%
Halton Hills Hydro Inc.	27.51	19.80	27.51	17	47.31	44.51	2.80	6.29%
Horizon Utilities Corporation	41.21	21.20	39.14	20.2	62.41	59.34	3.07	5.17%
Hydro Ottawa Limited	17.23	43.20	16.72	42	60.43	58.72	1.71	2.91%
Kingston Hydro Corporation	14.27	29.20	25.85	21.2	43.47	47.05	-3.58	-7.61%
Entegrus Powerlines Inc. - Strathroy, Mount Brydges & Parkhill	30	19.80	19.06	10.2	49.80	29.26	20.54	70.20%
Entegrus Powerlines Inc. - Dutton	30	19.80	27.45	12.2	49.80	39.65	10.15	25.60%
Entegrus Powerlines Inc. - Newbury	30	19.80	22.91	22.8	49.80	45.71	4.09	8.95%
Milton Hydro Distribution inc.	16.51	34.80	16.42	34.8	51.31	51.22	0.09	0.18%
Oshawa PUC Networks Inc.	16.02	31.40	8.38	34	47.42	42.38	5.04	11.89%
Ottawa River Power Corporation	22.02	25.00	22.97	21	47.02	43.97	3.05	6.94%
PowerStream Inc.	26.55	28.40	26.08	27.8	54.95	53.88	1.07	1.99%
Toronto Hydro-Electric System Limited	30.47	56.36	24.8	45.86	86.83	70.66	16.17	22.88%
Wasaga Distribution Inc.	14.76	29.80	13.54	27.4	44.56	40.94	3.62	8.84%
Waterloo North Hydro Inc.	31.96	31.80	31.96	28.6	63.76	60.56	3.20	5.28%
Wellington North Power Inc.	41.71	35.80	39.25	33.6	77.51	72.85	4.66	6.40%

Source of data: EB-2016-0055 (Algoma Power Inc. 2017 Rates Application). Hydro One received the detailed table above from Algoma Power Inc. (Algoma Power Inc. received this table from OEB staff). The table was compiled by OEB Staff and was used to determine the 2017 Algoma Power Inc. RRRP adjustment factor (see OEB Decision and Rate Order, issued on December 8, 2016, page 1).

2016/2015 Average Increase for GS<50 kW Class (Entegrus was excluded because rate increases were distorted by the impact of harmonization) 6.6%

2017/2016 Average Increase for Residential Class

Residential	2017 MFC	2017 VC	2016 MFC	2016 VC	TB 2017	TB 2016	$ change	% Change
Atikokan Hydro Inc.	42.31	6.00	36.95	8.32	48.31	45.27	3.04	6.72%
Brantford Power Inc.	17.80	6.08	14.64	8.80	23.88	23.44	0.44	1.88%
Canadian Niagara Power Inc. -Eastern Ontario Power	27.72	9.76		12.16	37.48	35.60	1.88	5.28%
Canadian Niagara Power Inc. -Fort Erie	27.72	9.76		12.16	37.48	35.60	1.88	5.28%
Canadian Niagara Power Inc. -Port Colborne Hydro Inc.	27.72	9.76		12.16	37.48	2018.00	1.88	5.28%
Horizon Utilities Corporation	21.34	6.48	18.80	9.68	27.82	28.48	-0.66	-2.32%
Hydro Ottawa Limited	16.60	12.08	12.96	15.44	28.68	28.40	0.28	0.99%
Kingston Hydro Corporation	18.54	6.56	13.98	11.12	25.10	25.10	0.00	0.00%
Lakefront Utilities Inc.	16.00	6.08	13.14	9.04	22.08	22.18	-0.10	-0.50%
London Hydro Inc.	19.34	6.56	16.42	9.68	25.90	26.10	-0.20	-0.77%
Northern Ontario Wires Inc.	30.30	7.36	24.25	9.84	37.66	34.09	3.57	10.47%
Oshawa PUC Networks Inc.	14.22	8.72	11.21	11.36	22.94	22.57	0.37	1.64%
PowerStream Inc.	18.51	10.40	12.90	11.44	28.91	24.34	4.57	18.78%
Renfrew Hydro Inc.	17.30	9.20	13.97	11.60	26.50	25.57	0.93	3.64%
Toronto Hydro-Electric System Limited	27.69	12.10	22.78	15.04	39.79	37.82	1.97	5.20%
Welland Hydro-Electric System Corp.	22.26	5.92	18.76	8.40	28.18	27.16	1.02	3.76%

Source of data: EB-2017-0051 (Hydro One Remote Communities Inc. 2018 Rates Application), Exhibit G1, Schedule 2, Tab 1, Attachment 1. This information was compiled by Board Staff and was used to determine 2018 Hydro One Remotes Communities Inc. rate increases.

2017/2016 Average Increase for Residential Class	4.1%

2017/2016 Average Increase for General Service<50 kW Class

General Service < 50kW	**2017 MFC**	**2017 VC**	**2016 MFC**	**2016 VC**	**TB 2017**	**TB 2016**	**$ change**	**% Change**
Atikokan Hydro Inc.	76.23	9.40	76.23	19.20	85.63	95.43	-9.80	-10.27%
Brantford Power Inc.	30.14	15.80	26.46	13.80	45.94	40.26	5.68	14.11%
Canadian Niagara Power Inc. -Eastern Ontario Power	30.02	48.80		46.00	78.82	74.26	4.56	6.14%
Canadian Niagara Power Inc. -Fort Erie	30.02	48.80		46.00	78.82	74.26	4.56	6.14%
Canadian Niagara Power Inc. -Port Colborne Hydro Inc.	30.02	48.80		46.00	78.82	2018.00	4.56	6.14%
Horizon Utilities Corporation	41.42	21.40	41.21	21.20	62.82	62.41	0.41	0.66%
Hydro Ottawa Limited	17.89	45.40	17.23	43.20	63.29	60.43	2.86	4.73%
Kingston Hydro Corporation	14.59	30.20	14.27	29.20	44.79	43.47	1.32	3.04%
Lakefront Utilities Inc.	23.96	16.40	23.96	17.20	40.36	41.16	-0.80	-1.94%
London Hydro Inc.	32.25	21.60	32.25	20.80	53.85	53.05	0.80	1.51%
Northern Ontario Wires Inc.	31.76	35.40	28.27	31.60	67.16	59.87	7.29	12.18%
Oshawa PUC Networks Inc.	16.24	32.20	16.02	31.40	48.44	47.42	1.02	2.15%
PowerStream Inc.	28.74	36.60	26.55	28.40	65.34	54.95	10.39	18.91%
Renfrew Hydro Inc.	31.25	30.60	31.25	30.60	61.85	61.85	0.00	0.00%
Toronto Hydro-Electric System Limited	32.68	60.46	30.47	56.36	93.14	86.83	6.31	7.27%
Welland Hydro-Electric System Corp.	30.91	18.20	29.23	17.20	49.11	46.43	2.68	5.77%

Source of data: EB-2017-0051 (Hydro One Remote Communities Inc. 2018 Rates Application), Exhibit G1, Schedule 2, Tab 1, Attachment 1. This information was compiled by Board Staff and was used to determine 2018 Hydro One Remotes Communities Inc. rate increases.

2017/2016 Average Increase for GS<50 kW Class **4.8%**

Bill Calculations Woodstock 2021

Woodstock_Residential									
	Volume	**Acquired Utility Rates at the time of Acquisition (2014)**	**Charges ($)**	**2021 Escalated Acquired Utility Rates**	**Charges ($)**	**Volume**	**2021 Hydro One Proposed Rates**	**Charges ($)**	**2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)**
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0431**					**1.057**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	12.98	$12.98	35.68	$35.68	1	30.78	$30.78	
DX Fixed Charge Rate Riders ($)	1	0.64	$0.64	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0222	$16.65	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0000	$0.00	0.0000	$0.00	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0004	-$0.30	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$29.97**		**$35.68**			**$30.78**	**-13.7%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	32	0.0822	$2.66	0.0822	$2.66	43	0.0822	$3.51	
Distribution Pass-through Charges			**$3.45**		**$3.45**			**$4.30**	**24.9%**
Total: Distribution			**$33.42**		**$39.13**			**$35.08**	**-10.3%**
TX-Network ($/kWh)	782	0.0075	$5.87	0.0072	$5.63	793	0.0073	$5.79	
TX-Connection ($/kWh)	782	0.0054	$4.22	0.0056	$4.38	793	0.0062	$4.92	
Total: Transmission			**$10.09**		**$10.01**			**$10.70**	**6.9%**
WMSC ($/kWh)	782	0.0036	$2.82	0.0036	$2.82	793	0.0036	$2.85	
RRRP ($/kWh)	782	0.0003	$0.23	0.0003	$0.23	793	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.30**		**$3.30**			**$3.34**	**1.2%**
Total Bill (Before Taxes)			$108.43		$114.06			$110.75	
HST		13%	$14.10	13%	$14.83		13%	$14.40	
Total Bill (Including HST)			$122.52		$128.89			$125.14	
OREC		-8%	-$9.80	-8%	-$10.31		-8%	-$10.01	
Total Bill (Including HST & OREC)			**$112.72**		**$118.58**			**$115.13**	**-2.9%**

Bill Calculations Woodstock 2021

Woodstock_General Service Less Than 50 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0431**					**1.057**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	25.19	$25.19	29.97	$29.97	1	28.42	$28.42	
DX Fixed Charge Rate Riders ($)	1	4.24	$4.24	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.0145	$29.00	0.0219	$43.80	2,000	0.0164	$32.80	
DX Low Voltage Charge ($/kWh)	2,000	0.0000	$0.00	0.0000	$0.00	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0005	-$1.00	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$57.43**		**$73.77**			**$61.22**	**-17.0%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	86	0.0822	$7.08	0.0822	$7.08	114	0.0822	$9.37	
Distribution Pass-through Charges			**$7.87**		**$7.87**			**$10.16**	**29.0%**
Total: Distribution			**$65.30**		**$81.64**			**$71.38**	**-12.6%**
TX-Network ($/kWh)	2,086	0.0068	$14.19	0.0065	$13.56	2,114	0.0056	$11.84	
TX-Connection ($/kWh)	2,086	0.0051	$10.64	0.0053	$11.06	2,114	0.0046	$9.72	
Total: Transmission			**$24.83**		**$24.62**			**$21.56**	**-12.4%**
WMSC ($/kWh)	2,086	0.0036	$7.51	0.0036	$7.51	2,114	0.0036	$7.61	
RRRP ($/kWh)	2,086	0.0003	$0.63	0.0003	$0.63	2,114	0.0003	$0.63	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.39**		**$22.39**			**$22.49**	**0.5%**
Total Bill (Before Taxes)			$276.83		$292.97			$279.75	
HST		13%	$35.99	13%	$38.09		13%	$36.37	
Total Bill (Including HST)			$312.82		$331.05			$316.12	
OREC		-8%	-$25.03	-8%	-$26.48		-8%	-$25.29	
Total Bill (Including HST & OREC)			**$287.80**		**$304.57**			**$290.83**	**-4.5%**

Bill Calculations Woodstock 2021

Woodstock_General Service 50-999 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**61,239**					**61,239**			
Peak (kW)	**177**					**177**			
Total Loss Factors	**1.0431**					**1.0465**			
Avg IESO WMP (Per 2018 IRM Model)	63,878	0.1101	$7,033.01	0.1101	$7,033.01	64,087	0.1101	$7,055.94	
Total: Commodity			**$7,033.01**		**$7,033.01**			**$7,055.94**	**0.3%**
DX Fixed Charge ($)	1	139.96	$139.96	166.55	$166.55	1	183.26	$183.26	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	177	2.5777	$456.25	3.0656	$542.61	177	3.4576	$612.00	
DX Low Voltage Charge ($/kW)	177	0.0000	$0.00	0.0000	$0.00	177	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	177	(0.7616)	-$134.80	0.0000	$0.00	177	0.0000	$0.00	
Total: Distribution			**$461.41**		**$709.16**			**$795.26**	**12.1%**
TX-Network ($/kW)	177	2.9187	$516.61	2.7931	$494.38	177	1.8612	$329.43	
TX-Connection ($/kW)	177	2.1784	$385.58	2.2465	$397.63	177	1.5062	$266.60	
Total: Transmission			**$902.19**		**$892.01**			**$596.03**	**-33.2%**
WMSC ($/kWh)	63,878	0.0036	$229.96	0.0036	$229.96	64,087	0.0036	$230.71	
RRRP ($/kWh)	63,878	0.0003	$19.16	0.0003	$19.16	64,087	0.0003	$19.23	
DRC ($/kWh)	61,239	0.007	$428.67	0.007	$428.67	61,239	0.007	$428.67	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$678.05**		**$678.05**			**$678.86**	**0.1%**
Total Bill (Before Taxes)			$9,074.66		$9,312.23			$9,126.08	
HST		13%	$1,179.71	13%	$1,210.59		13%	$1,186.39	
Total Bill (Including HST)			**$10,254.36**		**$10,522.82**			**$10,312.47**	**-2.0%**

Bill Calculations Norfolk 2021

Norfolk_Residential									
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0564**					**1.0667**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	20.87	$20.87	44.56	$44.56	1	37.70	$37.70	
DX Fixed Charge Rate Riders ($)	1	1.03	$1.03	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0218	$16.35	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0009	$0.68	0.0009	$0.68	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0002	-$0.15	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$38.78**		**$45.24**			**$37.70**	**-16.7%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	42	0.0822	$3.48	0.0822	$3.48	50	0.0822	$4.11	
Distribution Pass-through Charges			**$4.27**		**$4.27**			**$4.90**	**14.9%**
Total: Distribution			**$43.04**		**$49.50**			**$42.60**	**-13.9%**
TX-Network ($/kWh)	792	0.0067	$5.31	0.0068	$5.39	800	0.0071	$5.68	
TX-Connection ($/kWh)	792	0.0032	$2.54	0.0036	$2.85	800	0.0060	$4.80	
Total: Transmission			**$7.84**		**$8.24**			**$10.48**	**27.2%**
WMSC ($/kWh)	792	0.0036	$2.85	0.0036	$2.85	800	0.0036	$2.88	
RRRP ($/kWh)	792	0.0003	$0.24	0.0003	$0.24	800	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.34**		**$3.34**			**$3.37**	**0.9%**
Total Bill (Before Taxes)			$115.84		$122.70			$118.07	
HST		13%	$15.06	13%	$15.95		13%	$15.35	
Total Bill (Including HST)			$130.90		$138.65			$133.42	
OREC		-8%	-$10.47	-8%	-$11.09		-8%	-$10.67	
Total Bill (Including HST and OREC)			**$120.43**		**$127.56**			**$122.75**	**-3.8%**

Bill Calculations Norfolk 2021

Norfolk_General Service Less Than 50 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0564**					**1.0667**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	49.98	$49.98	60.54	$60.54	1	38.65	$38.65	
DX Fixed Charge Rate Riders ($)	1	4.35	$4.35	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.0156	$31.20	0.0219	$43.80	2,000	0.0177	$35.40	
DX Low Voltage Charge ($/kWh)	2,000	0.0008	$1.60	0.0008	$1.60	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0002	-$0.40	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$86.73**		**$105.94**			**$74.05**	**-30.1%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	113	0.0822	$9.27	0.0822	$9.27	133	0.0822	$10.96	
Distribution Pass-through Charges			**$10.06**		**$10.06**			**$11.75**	**16.8%**
Total: Distribution			**$96.79**		**$116.00**			**$85.80**	**-26.0%**
TX-Network ($/kWh)	2,113	0.0062	$13.10	0.0062	$13.10	2,133	0.0053	$11.31	
TX-Connection ($/kWh)	2,113	0.0028	$5.92	0.0031	$6.55	2,133	0.0044	$9.39	
Total: Transmission			**$19.02**		**$19.65**			**$20.69**	**5.3%**
WMSC ($/kWh)	2,113	0.0036	$7.61	0.0036	$7.61	2,133	0.0036	$7.68	
RRRP ($/kWh)	2,113	0.0003	$0.63	0.0003	$0.63	2,133	0.0003	$0.64	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.49**		**$22.49**			**$22.57**	**0.4%**
Total Bill (Before Taxes)			$302.61		$322.46			$293.38	
HST		13%	$39.34	13%	$41.92		13%	$38.14	
Total Bill (Including HST)			$341.95		$364.38			$331.52	
OREC		-8%	-$27.36	-8%	-$29.15		-8%	-$26.52	
Total Bill (Including HST & OREC)			**$314.60**		**$335.23**			**$305.00**	**-9.0%**

Bill Calculations Norfolk 2021

Norfolk_General Service 50-4,999 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**57,223**					**57,223**			
Peak (kW)	**161**					**161**			
Total Loss Factors	**1.0564**					**1.0563**			
Avg IESO WMP (Per 2018 IRM Model)	60,450	0.1101	$6,655.55	0.1101	$6,655.55	60,444	0.1101	$6,654.92	
Total: Commodity			**$6,655.55**		**$6,655.55**			**$6,654.92**	**0.0%**
DX Fixed Charge ($)	1	245.55	$245.55	297.46	$297.46	1	194.68	$194.68	
DX Fixed Charge Rate Riders ($)	1	(0.10)	-$0.10	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	161	3.9602	$637.41	4.7937	$771.56	161	4.8819	$785.76	
DX Low Voltage Charge ($/kW)	161	0.3050	$49.09	0.3050	$49.09	161	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	161	(0.9379)	-$150.96	0.0000	$0.00	161	0.0000	$0.00	
Total: Distribution			**$780.99**		**$1,118.11**			**$980.44**	**-12.3%**
TX-Network ($/kW)	161	2.4951	$401.59	2.5454	$409.69	161	1.8483	$297.49	
TX-Connection ($/kW)	161	1.1102	$178.69	1.2385	$199.34	161	1.5101	$243.06	
Total: Transmission			**$580.29**		**$609.03**			**$540.55**	**-11.2%**
WMSC ($/kWh)	60,450	0.0036	$217.62	0.0036	$217.62	60,444	0.0036	$217.60	
RRRP ($/kWh)	60,450	0.0003	$18.14	0.0003	$18.14	60,444	0.0003	$18.13	
DRC ($/kWh)	57,223	0.007	$400.56	0.007	$400.56	57,223	0.007	$400.56	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$636.56**		**$636.56**			**$636.54**	**0.0%**
Total Bill (Before Taxes)			$8,653.39		$9,019.26			$8,812.45	
HST		13%	$1,124.94	13%	$1,172.50		13%	$1,145.62	
Total Bill (Including HST)			**$9,778.33**		**$10,191.76**			**$9,958.07**	**-2.3%**

Bill Calculations Haldimand 2021

Haldimand_Residential									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0655**					**1.0667**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	17.01	$17.01	41.12	$41.12	1	37.70	$37.70	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0248	$18.60	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0004	$0.30	0.0004	$0.30	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0006	-$0.45	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$35.46**		**$41.42**			**$37.70**	**-9.0%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	49	0.0822	$4.04	0.0822	$4.04	50	0.0822	$4.11	
Distribution Pass-through Charges			**$4.83**		**$4.83**			**$4.90**	**1.5%**
Total: Distribution			**$40.29**		**$46.25**			**$42.60**	**-7.9%**
TX-Network ($/kWh)	799	0.0068	$5.43	0.0065	$5.19	800	0.0071	$5.68	
TX-Connection ($/kWh)	799	0.0052	$4.16	0.0054	$4.32	800	0.0060	$4.80	
Total: Transmission			**$9.59**		**$9.51**			**$10.48**	**10.2%**
WMSC ($/kWh)	799	0.0036	$2.88	0.0036	$2.88	800	0.0036	$2.88	
RRRP ($/kWh)	799	0.0003	$0.24	0.0003	$0.24	800	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.37**		**$3.37**			**$3.37**	**0.1%**
Total Bill (Before Taxes)			$114.86		$120.74			$118.07	
HST		13%	$14.93	13%	$15.70		13%	$15.35	
Total Bill (Including HST)			$129.79		$136.44			$133.42	
OREC		-8%	-$10.38	-8%	-$10.92		-8%	-$10.67	
Total Bill (Including HST & OREC)			**$119.41**		**$125.52**			**$122.75**	**-2.2%**

Bill Calculations Haldimand 2021

Haldimand_General Service Less Than 50 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0655**					**1.0667**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	26.94	$26.94	31.10	$31.10	1	38.65	$38.65	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.019	$38.00	0.0219	$43.80	2,000	0.0177	$35.40	
DX Low Voltage Charge ($/kWh)	2,000	0.0004	$0.80	0.0004	$0.80	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0009	-$1.80	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$63.94**		**$75.70**			**$74.05**	**-2.2%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	131	0.0822	$10.76	0.0822	$10.76	133	0.0822	$10.96	
Distribution Pass-through Charges			**$11.55**		**$11.55**			**$11.75**	**1.7%**
Total: Distribution			**$75.49**		**$87.25**			**$85.80**	**-1.7%**
TX-Network ($/kWh)	2,131	0.0061	$13.00	0.0059	$12.57	2,133	0.0053	$11.31	
TX-Connection ($/kWh)	2,131	0.0048	$10.23	0.0050	$10.66	2,133	0.0044	$9.39	
Total: Transmission			**$23.23**		**$23.23**			**$20.69**	**-10.9%**
WMSC ($/kWh)	2,131	0.0036	$7.67	0.0036	$7.67	2,133	0.0036	$7.68	
RRRP ($/kWh)	2,131	0.0003	$0.64	0.0003	$0.64	2,133	0.0003	$0.64	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.56**		**$22.56**			**$22.57**	**0.0%**
Total Bill (Before Taxes)			$285.60		$297.36			$293.38	
HST		13%	$37.13	13%	$38.66		13%	$38.14	
Total Bill (Including HST)			$322.73		$336.02			$331.52	
OREC		-8%	-$25.82	-8%	-$26.88		-8%	-$26.52	
Total Bill (Including HST & OREC)			**$296.91**		**$309.14**			**$305.00**	**-1.3%**

Bill Calculations Haldimand 2021

Haldimand_General Service 50-4,999 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2021 Escalated Acquired Utility Rates	Charges ($)	Volume	2021 Hydro One Proposed Rates	Charges ($)	2021 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**50,917**					**50,917**			
Peak (kW)	**143**					**143**			
Total Loss Factors	**1.0655**					**1.0563**			
Avg IESO WMP (Per 2018 IRM Model)	54,252	0.1101	$5,973.10	0.1101	$5,973.10	53,783	0.1101	$5,921.52	
Total: Commodity			**$5,973.10**		**$5,973.10**			**$5,921.52**	**-0.86%**
DX Fixed Charge ($)	1	83.61	$83.61	96.49	$96.49	1	194.68	$194.68	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	143	3.9339	$563.40	4.5409	$650.33	143	4.8819	$699.16	
DX Low Voltage Charge ($/kW)	143	0.1550	$22.20	0.1550	$22.20	143	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	143	0.5022	$71.92	0.0000	$0.00	143	0.0000	$0.00	
Total: Distribution			**$741.13**		**$769.02**			**$893.84**	**16.23%**
TX-Network ($/kW)	143	2.6016	$372.59	2.5038	$358.58	143	1.8483	$264.71	
TX-Connection ($/kW)	143	2.0329	$291.14	2.1172	$303.22	143	1.5101	$216.27	
Total: Transmission			**$663.73**		**$661.80**			**$480.98**	**-27.32%**
WMSC ($/kWh)	54,252	0.0036	$195.31	0.0036	$195.31	53,783	0.0036	$193.62	
RRRP ($/kWh)	54,252	0.0003	$16.28	0.0003	$16.28	53,783	0.0003	$16.13	
DRC ($/kWh)	50,917	0.007	$356.42	0.007	$356.42	50,917	0.007	$356.42	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$568.25**		**$568.25**			**$566.42**	**-0.32%**
Total Bill (Before Taxes)			$7,946.21		$7,972.16			$7,862.77	
HST		0.13	$1,033.01	13%	$1,036.38		13%	$1,022.16	
Total Bill (Including HST)			**$8,979.21**		**$9,008.54**			**$8,884.92**	**-1.37%**

Bill Calculations Woodstock 2022

Woodstock_Residential									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0431**					**1.057**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	12.98	$12.98	35.95	$35.95	1	31.59	$31.59	
DX Fixed Charge Rate Riders ($)	1	0.64	$0.64	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0222	$16.65	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0000	$0.00	0.0000	$0.00	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0004	-$0.30	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$29.97**		**$35.95**			**$31.59**	**-12.1%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	32	0.0822	$2.66	0.0822	$2.66	43	0.0822	$3.51	
Distribution Pass-through Charges			**$3.45**		**$3.45**			**$4.30**	**24.9%**
Total: Distribution			**$33.42**		**$39.40**			**$35.89**	**-8.9%**
TX-Network ($/kWh)	782	0.0075	$5.87	0.0072	$5.63	793	0.0073	$5.79	
TX-Connection ($/kWh)	782	0.0054	$4.22	0.0056	$4.38	793	0.0062	$4.92	
Total: Transmission			**$10.09**		**$10.01**			**$10.70**	**6.9%**
WMSC ($/kWh)	782	0.0036	$2.82	0.0036	$2.82	793	0.0036	$2.85	
RRRP ($/kWh)	782	0.0003	$0.23	0.0003	$0.23	793	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.30**		**$3.30**			**$3.34**	**1.2%**
Total Bill (Before Taxes)			$108.43		$114.33			$111.56	
HST		13%	$14.10	13%	$14.86		13%	$14.50	
Total Bill (Including HST)			$122.52		$129.19			$126.06	
OREC		-8%	-$9.80	-8%	-$10.34		-8%	-$10.08	
Total Bill (Including HST & OREC)			**$112.72**		**$118.86**			**$115.97**	**-2.4%**

Bill Calculations Woodstock 2022

Woodstock_General Service Less Than 50 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0431**					**1.057**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	25.19	$25.19	30.19	$30.19	1	29.14	$29.14	
DX Fixed Charge Rate Riders ($)	1	4.24	$4.24	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.0145	$29.00	0.0221	$44.20	2,000	0.0168	$33.60	
DX Low Voltage Charge ($/kWh)	2,000	0.0000	$0.00	0.0000	$0.00	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0005	-$1.00	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$57.43**		**$74.39**			**$62.74**	**-15.7%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	86	0.0822	$7.08	0.0822	$7.08	114	0.0822	$9.37	
Distribution Pass-through Charges			**$7.87**		**$7.87**			**$10.16**	**29.0%**
Total: Distribution			**$65.30**		**$82.26**			**$72.90**	**-11.4%**
TX-Network ($/kWh)	2,086	0.0068	$14.19	0.0065	$13.56	2,114	0.0056	$11.84	
TX-Connection ($/kWh)	2,086	0.0051	$10.64	0.0053	$11.06	2,114	0.0046	$9.72	
Total: Transmission			**$24.83**		**$24.62**			**$21.56**	**-12.4%**
WMSC ($/kWh)	2,086	0.0036	$7.51	0.0036	$7.51	2,114	0.0036	$7.61	
RRRP ($/kWh)	2,086	0.0003	$0.63	0.0003	$0.63	2,114	0.0003	$0.63	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.39**		**$22.39**			**$22.49**	**0.5%**
Total Bill (Before Taxes)			$276.83		$293.59			$281.27	
HST		13%	$35.99	13%	$38.17		13%	$36.57	
Total Bill (Including HST)			$312.82		$331.75			$317.84	
OREC		-8%	-$25.03	-8%	-$26.54		-8%	-$25.43	
Total Bill (Including HST & OREC)			**$287.80**		**$305.21**			**$292.41**	**-4.2%**

Bill Calculations Woodstock 2022

Woodstock_General Service 50-999 kW									
	Volume	**Acquired Utility Rates at the time of Acquisition (2014)**	**Charges ($)**	**2022 Escalated Acquired Utility Rates**	**Charges ($)**	**Volume**	**2022 Hydro One Proposed Rates**	**Charges ($)**	**2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)**
Monthly Consumption (kWh)	**61,239**					**61,239**			
Peak (kW)	**177**					**177**			
Total Loss Factors	**1.0431**					**1.0465**			
Avg IESO WMP (Per 2018 IRM Model)	63,878	0.1101	$7,033.01	0.1101	$7,033.01	64,087	0.1101	$7,055.94	
Total: Commodity			**$7,033.01**		**$7,033.01**			**$7,055.94**	**0.3%**
DX Fixed Charge ($)	1	139.96	$139.96	167.80	$167.80	1	188.20	$188.20	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	177	2.5777	$456.25	3.0886	$546.68	177	3.5426	$627.04	
DX Low Voltage Charge ($/kW)	177	0.0000	$0.00	0.0000	$0.00	177	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	177	(0.7616)	-$134.80	0.0000	$0.00	177	0.0000	$0.00	
Total: Distribution			**$461.41**		**$714.48**			**$815.24**	**14.1%**
TX-Network ($/kW)	177	2.9187	$516.61	2.7931	$494.38	177	1.8612	$329.43	
TX-Connection ($/kW)	177	2.1784	$385.58	2.2465	$397.63	177	1.5062	$266.60	
Total: Transmission			**$902.19**		**$892.01**			**$596.03**	**-33.2%**
WMSC ($/kWh)	63,878	0.0036	$229.96	0.0036	$229.96	64,087	0.0036	$230.71	
RRRP ($/kWh)	63,878	0.0003	$19.16	0.0003	$19.16	64,087	0.0003	$19.23	
DRC ($/kWh)	61,239	0.007	$428.67	0.007	$428.67	61,239	0.007	$428.67	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$678.05**		**$678.05**			**$678.86**	**0.1%**
Total Bill (Before Taxes)			$9,074.66		$9,317.55			$9,146.07	
HST		13%	$1,179.71	13%	$1,211.28		13%	$1,188.99	
Total Bill (Including HST)			**$10,254.36**		**$10,528.83**			**$10,335.06**	**-1.8%**

Bill Calculations Norfolk 2022

Norfolk_Residential									
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0564**					**1.0667**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	20.87	$20.87	44.96	$44.96	1	38.69	$38.69	
DX Fixed Charge Rate Riders ($)	1	1.03	$1.03	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0218	$16.35	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0009	$0.68	0.0009	$0.68	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0002	-$0.15	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$38.78**		**$45.64**			**$38.69**	**-15.2%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	42	0.0822	$3.48	0.0822	$3.48	50	0.0822	$4.11	
Distribution Pass-through Charges			**$4.27**		**$4.27**			**$4.90**	**14.9%**
Total: Distribution			**$43.04**		**$49.90**			**$43.59**	**-12.6%**
TX-Network ($/kWh)	792	0.0067	$5.31	0.0068	$5.39	800	0.0071	$5.68	
TX-Connection ($/kWh)	792	0.0032	$2.54	0.0036	$2.85	800	0.0060	$4.80	
Total: Transmission			**$7.84**		**$8.24**			**$10.48**	**27.2%**
WMSC ($/kWh)	792	0.0036	$2.85	0.0036	$2.85	800	0.0036	$2.88	
RRRP ($/kWh)	792	0.0003	$0.24	0.0003	$0.24	800	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.34**		**$3.34**			**$3.37**	**0.9%**
Total Bill (Before Taxes)			$115.84		$123.10			$119.06	
HST		13%	$15.06	13%	$16.00		13%	$15.48	
Total Bill (Including HST)			$130.90		$139.10			$134.54	
OREC		-8%	-$10.47	-8%	-$11.13		-8%	-$10.76	
Total Bill (Including HST and OREC)			**$120.43**		**$127.98**			**$123.78**	**-3.3%**

Bill Calculations Norfolk 2022

Norfolk_General Service Less Than 50 kW										
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0564**					**1.0667**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	49.98	$49.98	61.08	$61.08	1	39.44	$39.44	
DX Fixed Charge Rate Riders ($)	1	4.35	$4.35	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.0156	$31.20	0.0221	$44.20	2,000	0.0183	$36.60	
DX Low Voltage Charge ($/kWh)	2,000	0.0008	$1.60	0.0008	$1.60	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0002	-$0.40	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$86.73**		**$106.88**			**$76.04**	**-28.9%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	113	0.0822	$9.27	0.0822	$9.27	133	0.0822	$10.96	
Distribution Pass-through Charges			**$10.06**		**$10.06**			**$11.75**	**16.8%**
Total: Distribution			**$96.79**		**$116.94**			**$87.79**	**-24.9%**
TX-Network ($/kWh)	2,113	0.0062	$13.10	0.0062	$13.10	2,133	0.0053	$11.31	
TX-Connection ($/kWh)	2,113	0.0028	$5.92	0.0031	$6.55	2,133	0.0044	$9.39	
Total: Transmission			**$19.02**		**$19.65**			**$20.69**	**5.3%**
WMSC ($/kWh)	2,113	0.0036	$7.61	0.0036	$7.61	2,133	0.0036	$7.68	
RRRP ($/kWh)	2,113	0.0003	$0.63	0.0003	$0.63	2,133	0.0003	$0.64	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.49**		**$22.49**			**$22.57**	**0.4%**
Total Bill (Before Taxes)			$302.61		$323.40			$295.37	
HST		13%	$39.34	13%	$42.04		13%	$38.40	
Total Bill (Including HST)			$341.95		$365.44			$333.77	
OREC		-8%	-$27.36	-8%	-$29.24		-8%	-$26.70	
Total Bill (Including HST & OREC)			**$314.60**		**$336.20**			**$307.07**	**-8.7%**

Bill Calculations Norfolk 2022

Norfolk_General Service 50-4,999 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2013)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**57,223**					**57,223**			
Peak (kW)	**161**					**161**			
Total Loss Factors	**1.0564**					**1.0563**			
Avg IESO WMP (Per 2018 IRM Model)	60,450	0.1101	$6,655.55	0.1101	$6,655.55	60,444	0.1101	$6,654.92	
Total: Commodity			**$6,655.55**		**$6,655.55**			**$6,654.92**	**0.0%**
DX Fixed Charge ($)	1	245.55	$245.55	300.14	$300.14	1	197.06	$197.06	
DX Fixed Charge Rate Riders ($)	1	(0.10)	-$0.10	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	161	3.9602	$637.41	4.8368	$778.50	161	5.0222	$808.34	
DX Low Voltage Charge ($/kW)	161	0.3050	$49.09	0.3050	$49.09	161	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	161	(0.9379)	-$150.96	0.0000	$0.00	161	0.0000	$0.00	
Total: Distribution			**$780.99**		**$1,127.73**			**$1,005.40**	**-10.8%**
TX-Network ($/kW)	161	2.4951	$401.59	2.5454	$409.69	161	1.8483	$297.49	
TX-Connection ($/kW)	161	1.1102	$178.69	1.2385	$199.34	161	1.5101	$243.06	
Total: Transmission			**$580.29**		**$609.03**			**$540.55**	**-11.2%**
WMSC ($/kWh)	60,450	0.0036	$217.62	0.0036	$217.62	60,444	0.0036	$217.60	
RRRP ($/kWh)	60,450	0.0003	$18.14	0.0003	$18.14	60,444	0.0003	$18.13	
DRC ($/kWh)	57,223	0.007	$400.56	0.007	$400.56	57,223	0.007	$400.56	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$636.56**		**$636.56**			**$636.54**	**0.0%**
Total Bill (Before Taxes)			$8,653.39		$9,028.88			$8,837.41	
HST		13%	$1,124.94	13%	$1,173.75		13%	$1,148.86	
Total Bill (Including HST)			**$9,778.33**		**$10,202.63**			**$9,986.27**	**-2.1%**

Bill Calculations Haldimand 2022

Haldimand_Residential									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**750**					**750**			
Total Loss Factors	**1.0655**					**1.0667**			
TOU - Off Peak Consumption	488	0.065	$31.69	0.065	$31.69	488	0.065	$31.69	
TOU - Mid Peak Consumption	128	0.095	$12.11	0.095	$12.11	128	0.095	$12.11	
TOU - On Peak Consumption	135	0.132	$17.82	0.132	$17.82	135	0.132	$17.82	
Total: Commodity			**$61.62**		**$61.62**			**$61.62**	**0.0%**
DX Fixed Charge ($)	1	17.01	$17.01	41.55	$41.55	1	38.69	$38.69	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	750	0.0248	$18.60	0.0000	$0.00	750	0.0000	$0.00	
DX Low Voltage Charge ($/kWh)	750	0.0004	$0.30	0.0004	$0.30	750	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	750	-0.0006	-$0.45	0.0000	$0.00	750	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$35.46**		**$41.85**			**$38.69**	**-7.6%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	49	0.0822	$4.04	0.0822	$4.04	50	0.0822	$4.11	
Distribution Pass-through Charges			**$4.83**		**$4.83**			**$4.90**	**1.5%**
Total: Distribution			**$40.29**		**$46.68**			**$43.59**	**-6.6%**
TX-Network ($/kWh)	799	0.0068	$5.43	0.0065	$5.19	800	0.0071	$5.68	
TX-Connection ($/kWh)	799	0.0052	$4.16	0.0054	$4.32	800	0.0060	$4.80	
Total: Transmission			**$9.59**		**$9.51**			**$10.48**	**10.2%**
WMSC ($/kWh)	799	0.0036	$2.88	0.0036	$2.88	800	0.0036	$2.88	
RRRP ($/kWh)	799	0.0003	$0.24	0.0003	$0.24	800	0.0003	$0.24	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$3.37**		**$3.37**			**$3.37**	**0.1%**
Total Bill (Before Taxes)			$114.86		$121.17			$119.06	
HST		13%	$14.93	13%	$15.75		13%	$15.48	
Total Bill (Including HST)			$129.79		$136.92			$134.54	
OREC		-8%	-$10.38	-8%	-$10.95		-8%	-$10.76	
Total Bill (Including HST & OREC)			**$119.41**		**$125.97**			**$123.78**	**-1.7%**

Bill Calculations Haldimand 2022

Haldimand_General Service Less Than 50 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**2,000**					**2,000**			
Total Loss Factors	**1.0655**					**1.0667**			
TOU - Off Peak Consumption	1,300	0.065	$84.50	0.065	$84.50	1,300	0.065	$84.50	
TOU - Mid Peak Consumption	340	0.095	$32.30	0.095	$32.30	340	0.095	$32.30	
TOU - On Peak Consumption	360	0.132	$47.52	0.132	$47.52	360	0.132	$47.52	
Total: Commodity			**$164.32**		**$164.32**			**$164.32**	**0.0%**
DX Fixed Charge ($)	1	26.94	$26.94	31.43	$31.43	1	39.44	$39.44	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kWh)	2,000	0.019	$38.00	0.0221	$44.20	2,000	0.0183	$36.60	
DX Low Voltage Charge ($/kWh)	2,000	0.0004	$0.80	0.0004	$0.80	2,000	0.0000	$0.00	
DX Vol. Rate Riders ($/kWh)	2,000	-0.0009	-$1.80	0.0000	$0.00	2,000	0.0000	$0.00	
Distribution (Excl. Pass-through Charges)			**$63.94**		**$76.43**			**$76.04**	**-0.5%**
Smart Meter Entity Charge ($)	1	0.79	$0.79	0.79	$0.79	1	0.79	$0.79	
Cost of Losses ($/kWh)	131	0.0822	$10.76	0.0822	$10.76	133	0.0822	$10.96	
Distribution Pass-through Charges			**$11.55**		**$11.55**			**$11.75**	**1.7%**
Total: Distribution			**$75.49**		**$87.98**			**$87.79**	**-0.2%**
TX-Network ($/kWh)	2,131	0.0061	$13.00	0.0059	$12.57	2,133	0.0053	$11.31	
TX-Connection ($/kWh)	2,131	0.0048	$10.23	0.0050	$10.66	2,133	0.0044	$9.39	
Total: Transmission			**$23.23**		**$23.23**			**$20.69**	**-10.9%**
WMSC ($/kWh)	2,131	0.0036	$7.67	0.0036	$7.67	2,133	0.0036	$7.68	
RRRP ($/kWh)	2,131	0.0003	$0.64	0.0003	$0.64	2,133	0.0003	$0.64	
DRC ($/kWh)	2,000	0.007	$14.00	0.007	$14.00	2,000	0.007	$14.00	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$22.56**		**$22.56**			**$22.57**	**0.0%**
Total Bill (Before Taxes)			$285.60		$298.09			$295.37	
HST		13%	$37.13	13%	$38.75		13%	$38.40	
Total Bill (Including HST)			$322.73		$336.84			$333.77	
OREC		-8%	-$25.82	-8%	-$26.95		-8%	-$26.70	
Total Bill (Including HST & OREC)			**$296.91**		**$309.90**			**$307.07**	**-0.9%**

Bill Calculations Haldimand 2022

Haldimand_General Service 50-4,999 kW									
	Volume	Acquired Utility Rates at the time of Acquisition (2014)	Charges ($)	2022 Escalated Acquired Utility Rates	Charges ($)	Volume	2022 Hydro One Proposed Rates	Charges ($)	2022 Hydro One Proposed VS Escalated Acquired Utility Charges (%)
Monthly Consumption (kWh)	**50,917**					**50,917**			
Peak (kW)	**143**					**143**			
Total Loss Factors	**1.0655**					**1.0563**			
Avg IESO WMP (Per 2018 IRM Model)	54,252	0.1101	$5,973.10	0.1101	$5,973.10	53,783	0.1101	$5,921.52	
Total: Commodity			**$5,973.10**		**$5,973.10**			**$5,921.52**	**-0.9%**
DX Fixed Charge ($)	1	83.61	$83.61	97.50	$97.50	1	197.06	$197.06	
DX Fixed Charge Rate Riders ($)	1	0.00	$0.00	0.00	$0.00	1	0.00	$0.00	
DX Vol. Charge ($/kW)	143	3.9339	$563.40	4.5886	$657.16	143	5.0222	$719.26	
DX Low Voltage Charge ($/kW)	143	0.1550	$22.20	0.1550	$22.20	143	0.0000	$0.00	
DX Vol. Rate Riders ($/kW)	143	0.5022	$71.92	0.0000	$0.00	143	0.0000	$0.00	
Total: Distribution			**$741.13**		**$776.86**			**$916.32**	**18.0%**
TX-Network ($/kW)	143	2.6016	$372.59	2.5038	$358.58	143	1.8483	$264.71	
TX-Connection ($/kW)	143	2.0329	$291.14	2.1172	$303.22	143	1.5101	$216.27	
Total: Transmission			**$663.73**		**$661.80**			**$480.98**	**-27.3%**
WMSC ($/kWh)	54,252	0.0036	$195.31	0.0036	$195.31	53,783	0.0036	$193.62	
RRRP ($/kWh)	54,252	0.0003	$16.28	0.0003	$16.28	53,783	0.0003	$16.13	
DRC ($/kWh)	50,917	0.007	$356.42	0.007	$356.42	50,917	0.007	$356.42	
SSA ($)	1	0.25	$0.25	0.25	$0.25	1	0.25	$0.25	
Total: Regulatory			**$568.25**		**$568.25**			**$566.42**	**-0.3%**
Total Bill (Before Taxes)			$7,946.21		$7,980.00			$7,885.24	
HST		0.13	$1,033.01	13%	$1,037.40		13%	$1,025.08	
Total Bill (Including HST)			**$8,979.21**		**$9,017.40**			**$8,910.32**	**-1.2%**

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Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

June 29, 2017

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

Dear Ms. Walli,

RE: Web-based Process for Revising Data Filed under the OEB's Reporting and Record Keeping Requirements

Hydro One Networks Inc. ("**Hydro One**") submits this letter in response to the Ontario Energy Board's ("**OEB**" or "**Board**") letter dated May 3, 2016 regarding the Web-based Process for Revising Data Filed under the OEB's Reporting and Record Keeping Requirements ("**RRR reporting**").

In its May 3 letter, the Board outlines the requirement regarding the completeness, accuracy, and quality of RRR reporting and the importance of identifying to the Board any issues arising with respect to data integrity, including corrections to previously filed data:

Regulated entities are the owners of their reported RRR data and, as such, are responsible for the completeness, accuracy and quality of this data. Accordingly, it is important that any issues arising with respect to data integrity including corrections to previously filed data be brought to the OEB's attention immediately.

In response to the Board's audit of 2014 ROE filings of electricity distributors, Hydro One undertook and has recently completed a review of its RRR Reporting Section 2.1.5.6 Regulated Return on Equity ("**ROE**") for the period 2010 to 2015. The results of this review are presented in Table 1. The review was prepared in accordance with the guidelines established in the Board's RRR 2.1.5.6 ROE Complete Filing Guide, and identified adjustments mainly related to the treatment of Construction Work In Progress (CWIP); Property, Plant, & Equipment; and regulatory tax adjustments.

Table 1 – Regulated ROE for Hydro One Distribution

in per cent	***2010***	***2011***	***2012***	***2013***	***2014***	***2015***
Deemed	9.85	9.66	9.66	9.66	9.66	9.30
ROE-reported	8.25	8.80	8.72	8.00	6.26	8.77
ROE-revised	**8.78**	**9.96**	**9.93**	**8.96**	**5.47**	**8.63**
Delta – Reported to deemed	(1.60)	(0.86)	(0.94)	(1.66)	(3.40)	(0.53)
Delta – Revised to deemed	**(1.07)**	**0.30**	**0.27**	**(0.70)**	**(4.19)**	**(0.67)**
ROE status-reported relative to OEB deadband	Within	Within	Within	Within	Under-earning	Within
ROE status-revised relative to 300 bps deadband	**Within**	**Within**	**Within**	**Within**	**Under-earning**	**Within**

Hydro One has kept Board Staff informed of this review and of its results. The Company recognizes the importance of reporting accurate and reliable RRR data, and as such has increased its oversight of the processes and controls in-place to support the ongoing accurate calculation and reporting of the ROE.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert