EB-2017-0049

HYDRO ONE NETWORKS INC.

DISTRIBUTION RATES APPLICATION – 2018-2022

CME COMPENDIUM

PANEL 1

June 11, 2018

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hydroOne

Distribution Business Plan 2017-2022

December 2, 2016

INTERNAL and CONFIDENTIAL

As a result of this approach, the investment planning process that culminated in this Distribution Business Plan and the Distribution System Plan described herein was iterative; Hydro One created several different asset investment plans with different customer outcomes and rate impacts, and these plans were evaluated by the Executive Leadership Team and discussed with the company's Board of Directors. The Distribution Business Plan and the associated Distribution System Plan in this document represent an investment plan that appropriately aligns the needs and preferences of customers, customer rates and effective stewardship of the distribution system by Hydro One.

Circumstances & Challenges

Hydro One 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 100,000 kilometers of rights-of-way, and although the majority of the company's distribution power lines are along roadways, one-third of the lines are off-road, requiring the use of special equipment for access and maintenance.

Reliability

Reliability performance is affected by factors such as: 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

Much of Hydro One's distribution system was built in the 1950s and 1960s and as a result, many of the company's assets are approaching or beyond the end of their expected service life. While replacement decisions are based on actual asset condition, age is an indicator of additional asset replacements over the business planning period. For example, Hydro One currently has 240,000 wood poles (15% of fleet) that are beyond their expected service life of 60 years and 144 station transformers (12% of fleet) 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

- *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.
- *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 HONI Dx 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.

It is worth noting that when Residential & Small Business customers were informed that to maintain reliability and customer service, a typical customer's monthly bill would need to increase by about 1% ($2.00), about half of Residential and Seasonal customers were willing to accept it.

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;
- Hydro One has implemented a number of productivity initiatives to reduce unit and operating costs. Executing on identified productivity and efficiency enhancements to change and reduce its cost structure is expected to result in lower customer rates;
- Hydro One's overall business plan was optimized such that distribution reliability will not deteriorate. For example, pursuant to the pole replacement program, 77,400 poles will

be replaced over the term of the plan, managing the aging pole population and addressing the volume of poles that have been assessed to be in poor condition;

- A top priority for Large Customers is to improve power quality. Hydro One has therefore created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue that they are experiencing. This program has been budgeted to complete one audit per year;
- To help address Power Quality issues for Hydro One's Large Customers a capital power quality program has been incorporated into the plan. This program will install power quality meters when needed to assist in power quality investigations, install surge arresters, or improve grounding. Approximately $200 thousand per year has been allocated to this work;
- Hydro One has increased the funding for reliability enhancement projects to specifically target Large Distribution Account (LDA) and mid-size industrial customers. These projects will be selected to improve system reliability where concerns have been raised by Hydro One's LDA and mid-size industrial customers that a performance issue with the existing network. 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 approximately $1.5 million per year; and
- Residential and Small Business customers requested that Hydro One maintain its existing level of reliability. To prevent an overall deterioration in reliability, Hydro One will be improving reliability on the worst performing feeders in the Province. This program will deploy communication to the open point switches, and install sectionalizers and feeder breakers. 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.

The Distribution System Plan reflected in this Distribution Business Plan seeks to meet customers' needs regarding reliability and power quality, in a manner that produces outcomes that are valued by customers.

Customer Initiatives

In order to provide better service for Hydro One customers, the following major customer initiatives have been included in the business plan that will deliver cost savings and improved customer experiences:

Initiative	Description	Cost
eBilling	The number of eBilling customers is expected to increase from 8% currently to over 40% in 2022. This will result in a reduction of paper bill volumes and significant reduction in associated postage costs.	$12.6 million

2018 capital expenditure level would only be sustainable for one year. Also, the plan does not include a capital true-up in 2019-2022 for the reduction outlined in 2018.

Plan B "as modified" capital adjustments included a $5 million reduction in IT spend, $25 million reduction in the wood pole program, $15 million reduction in station refurbishment investment, $10 million in component replacement activities and $10 million reduction in facilities and fleet investments in 2018. Final plan has an average capital spend over 2018 to 2022 of $732 million.

The summary of 2017 to 2022 distribution capital expenditures is set out in the table below.

Summary of Distribution Capital Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Sustaining	$ 302	$ 282	$ 346	$ 369	$ 383	$ 467
Development	$ 217	$ 230	$ 240	$ 233	$ 232	$ 233
Operations	$ 13	$ 17	$ 46	$ 6	$ 7	$ 9
Corp Common Costs & Other Capital	$ 102	$ 106	$ 124	$ 111	$ 110	$ 109
Total	**$ 634**	**$ 634**	**$ 757**	**$ 719**	**$ 731**	**$ 818**

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 investment costs are projected to decline in 2017 due mainly to the completion of the metering CDMA replacement project and the expected decrease in distributed generation connections. New connections, line relocations, and service upgrades make up the bulk of activities in this category over the first four years leading to increases in-line with inflation. There is a significant increase in projected spending in 2022, which reflects the anticipated commencement of smart meter replacement, as the current population of smart meters approach end of service life.

System Renewal

System Renewal investment costs are projected to increase by an average of 3.7% annually during the forecast period. Storm damage restoration, pole replacements, and distribution station refurbishments make up the bulk of the activities in this category. Storm damage restoration costs are expected to remain flat. The pole replacement program is expected to increase until 2020 to address poles that have reached the end of their expected useful life and then level off thereafter. The station refurbishment program is expected to continue increasing over time to reflect the growing number of assets expected to reach the end of their useful life.

System Service

While System Service investment costs are projected to fall slightly over the Distribution System Plan period, Hydro One expects variability from year-to-year based on specific investment needs. The bulk of these investments accommodate increases in load that will constrain the ability of the system to provide consistent service. To alleviate this constraint, a number of investments throughout the province are planned to upgrade capacity of Hydro One's distribution assets.

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Distribution Business Plan 2018-2023

December 8, 2017

INTERNAL and CONFIDENTIAL

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,

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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.

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

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

Hydro One Limited/ Hydro One Inc.
Submission to the Board of Directors

hydroOne

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Date: November 11, 2016

Re: Application for Distribution Rates 2018 to 2022

Attached for information is a summary of progress to date of the Distribution Investment Plan for the five year Distribution rate filing that is expected to be filed on March 3rd, 2017. The information is provided for feedback and input.

Significant inclusions/changes since the last Board meeting include:

1. A potential path to accomplish a 2018 rate increase of 5.4% (average of 3.4% over 5 years).
2. Detailed analysis of the effects of various options on customer bills and reliability.
3. Data on asset replacement rates and impacts on asset condition.
4. Analysis of productivity initiatives and outcomes on capital and OM&A
5. Summaries of customer feedback and the impact of such feedback on the plan.
6. Some history of OEB decisions to provide context on OEB expectations for this filing.

For the last several months, our teams have worked diligently to analyse trade-offs between customer and reliability impacts and customer bill impacts. In working to the optimum outcomes, we have considered overall reductions in the capital program, short-term capital reductions and more aggressive and targeted cost reduction to further reduce the overall bill impact arising from OM&A and corporate costs. Our focus was to find ways to reduce the average bill impact over the five year period, but also reduce the first year (2018) bill impact that already has non-actionable rate increases of 5.1% included. Our latest iteration has succeeded in adding only 0.3% in rate increases to the minimum bill impact in 2018.

The analyses provided are for feedback only. Management is not making a recommendation at this time. We will incorporate your feedback into the further analysis that we continue to perform, and expect to provide a final recommendation that will be included in a detailed business plan for Board approval at the December 2016 meeting.

We have attempted to keep the analysis as clear as possible, while providing relevant data.The subject is complex, and I would be pleased to discuss or answer questions of clarification before the meeting.

Yours sincerely,

Michael Vels
Chief Financial Officer

EXI-3-SEC-4
ATT. 3.
FEB. 10, 2017

Table 1. Financial Metrics 2018 to 2022 Hydro One Distribution Application

Distribution Revenue Requirement	2017	2018	2019	2020	2021	2022
	OEB Approved					
Capital Expenditures	$ 661	$ 634	$ 757	$ 719	$ 741	$ 827
In-Service Additions	$ 696	$ 641	$ 776	$ 768	$ 734	$ 815
Rate Base	**$ 7,190**	**$ 7,672**	**$ 8,049**	**$ 8,477**	**$ 9,035**	**$ 9,435**
OM&A	$ 593	$ 592	$ 600	$ 607	$ 626	$ 634
Depreciation	$ 390	$ 394	$ 414	$ 429	$ 448	$ 465
Return on Debt	$ 183	$ 191	$ 200	$ 211	$ 225	$ 235
Return on Equity	$ 253	$ 269	$ 283	$ 298	$ 317	$ 331
Income Tax	$ 49	$ 58	$ 61	$ 63	$ 69	$ 70
Revenue Requirement	**$ 1,468**	**$ 1,505**	**$ 1,558**	**$ 1,607**	**$ 1,685**	**$ 1,735**
Rate Riders	$ 11	$ 23	$ 23	$ 23	$ 23	$ 23
Other revenue impacts	$ (53)	$ (49)	$ (49)	$ (49)	$ (50)	$ (50)
Rates Revenue Requirement	**$ 1,426**	**$ 1,479**	**$ 1,532**	**$ 1,581**	**$ 1,658**	**$ 1,707**
Rate Increase Required, excluding Load		**3.7%**	**3.6%**	**3.2%**	**4.9%**	**3.0%**
Estimated Load Impact		2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Rate Increase Required		**5.7%**	**3.4%**	**2.5%**	**2.4%**	**2.4%**
Estimated Total Bill Impact (R1 customer - 30%)		**1.7%**	**1.0%**	**0.7%**	**0.7%**	**0.7%**

The drivers of the proposed distribution rate increases over the 2018 to 2022 period are set out in Table 2. The average rate increase over the 5-year period is 3.3%. As discussed in November 2016, approximately 5.1% or 90% of the rate increase in 2018 is attributable to factors that cannot be controlled at this time by Hydro One. Proposed increases in rates in 2019 through 2022 are driven by planned capital additions in each year, consistent with the Distribution Business Plan approved by the Board in December 2016.

Table 2. Drivers of Proposed Distribution Rates Increases 2018 to 2022

Distribution Rate Drivers	2018	2019	2020	2021	2022
OM&A	-0.1%	0.5%	0.5%	1.2%	0.5%
Rate Base & Depreciation	2.0%	2.9%	2.6%	3.3%	2.5%
Income Taxes	0.7%	0.2%	0.1%	0.4%	0.1%
Rate Riders	0.8%	0.0%	0.0%	0.0%	0.0%
Estimated Load Impact	2.0%	-0.2%	-0.7%	-2.5%	-0.6%
External Revenues - Other	0.3%	0.0%	0.0%	-0.1%	0.0%
Total	5.7%	3.4%	2.5%	2.4%	2.4%

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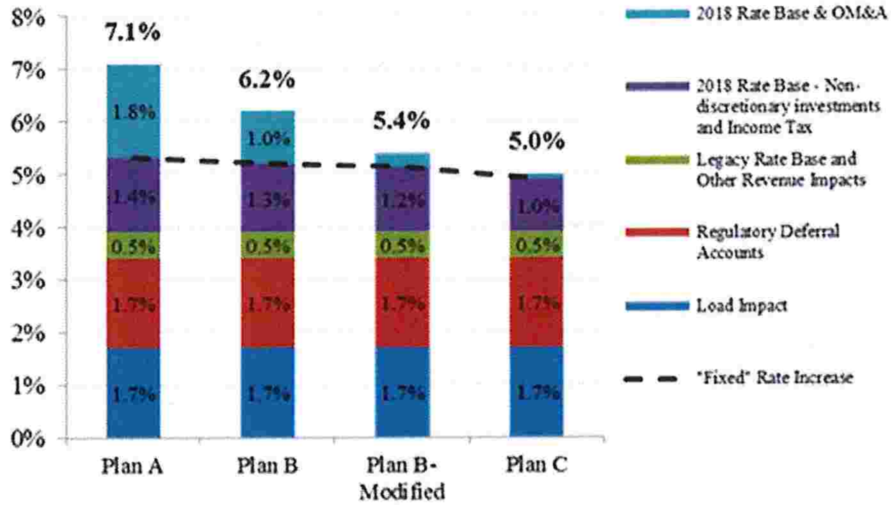
C." Considering the unacceptable negative reliability and customer satisfaction outcomes over five years arising from Plan C, we then considered a range of more targeted options that trade off reliability impacts and impacts on rates. This is identified in this document as "Plan B Modified". Each scenario provides alternate outcomes and trade-offs between customer cost and preferences, company performance, and system risk over the 2018 to 2022 period, all of which the Executive Leadership Team will be considering as they arrive at a final recommendation. Bill impact amounts shown below are Distribution only (excludes Transmission) and have not been calculated as yet for Plan B – Modified.

Figure: 2018 Rate Impacts



	Plan A	Plan B	Plan B-Modified	Plan C
Average Annual Rate Increase (vs. 2017)	**3.7%**	**3.5%**	**3.4%**	**2.8%**
2022 – R1 Customer - Hydro One Rate (Dx) Impact (vs. 2017)	**$3.91**	**$3.42**	**TBD**	**$2.76**

As noted above, common to all three plans is a "fixed" rate increase for 2018 based on activities between 2014 and 2016 that cannot be practically influenced. After adding non-discretionary asset spend and taxation, the minimum rate increase for 2018 is approximately 5.1%, varying slightly between each scenario. These variances, and the effect on each plan, are further summarized in the waterfall charts below for Plan A and a modified Plan B, and can be explained as follows:

- *Load Impact*: As part of the design of the regulatory framework, a load forecast must be provided and the base year trued up for variances that, until then will have been borne by the utility (1.7%).
- *Regulatory deferral accounts* that have not been reflected in rates must be trued up according to OEB direction (1.0%).
- *Legacy Rate Base*: Hydro One has approximately $105M of additional work completed in 2015 above the prior revenue allowance that must be recovered in rates, referred to above as legacy rate base (0.5%).
- *Non-discretionary capital spending* that impacts the 2108 rate base include mandatory investments to connect load and generation customers, responding to storm damage and trouble calls, maintaining and enhancing the meter network, and sustaining operating infrastructure (0.5%).

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As a result, in the 2018 rebasing year, between capital factors and OM&A, Hydro has approximately 2.4% of rate impact that can be adjusted to affect lower rates for customers. In all circumstances, Hydro One has built a plan where OM&A levels positively impacts rates by at least 0.4%, i.e., the contribution of productivity has reduced rates in excess of inflation, including productivity and cost reductions of approximately 2%.

Figure: 2018 Rate Impact of Plan A

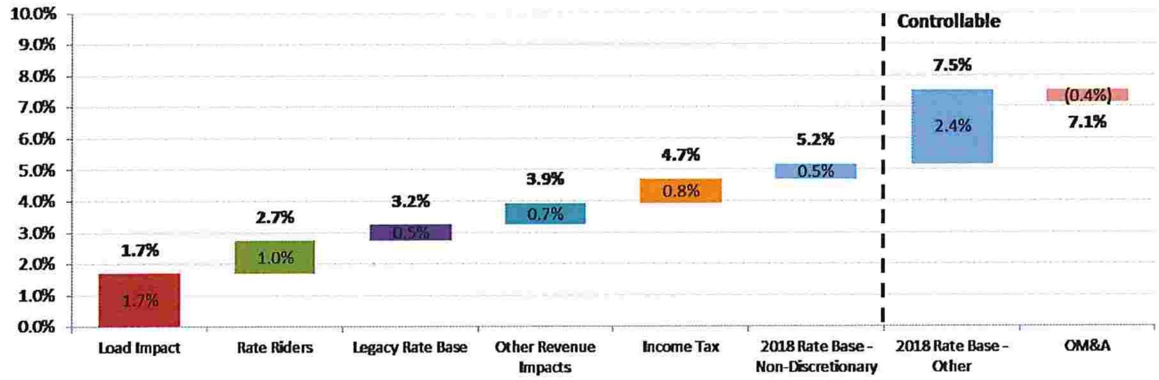
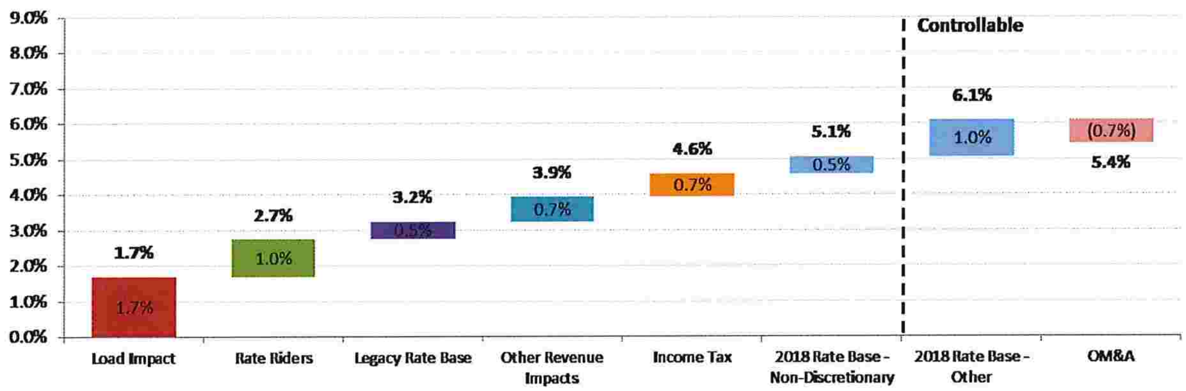


Figure: 2018 Rate Impact of Plan B - Modified



Summarised below is the capital profile of the primary scenarios and their outcomes. Capital categories include:

- Non-Discretionary: as defined above; not optional and cannot be eliminated or deferred.
- Shared Services: investments to sustain common support infrastructure.
- Discretionary/Asset Renewal: investments to enhance technology platforms and the pacing of asset replacements/refurbishments, including poles and stations.

Electricity Distributor Scorecard

Performance Outcomes	Performance Categories	Measures	ACTUALS 2011	2012	2013	2014	2015	2016	2017	TARGETS 2017	2018	2019	2020	2021	2022
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	92.00%	95.70%	97.40%	97.40%	97.50%	98.60%	98.06%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
		Scheduled Appointments Met On Time	93.90%	98.60%	98.40%	99.30%	98.50%	99.50%	98.94%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Telephone Calls Answered On Time	81.40%	83.40%	63.90%	69.60%	76.40%	74.20%	82.00%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
	Customer Satisfaction	First Contact Resolution*			78.30%	79.00%	82.00%	82.00%	85.00%	85.0%	86.0%	87.0%	87.0%	88.0%	88.0%
		Billing Accuracy				94.63%	98.59%	99.04%	99.30%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Customer Satisfaction Survey Results*			87.00%	85.00%	85.00%	84.00%	84.90%	86.0%	87.0%	87.5%	88.0%	88.5%	89.0%
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness					81.00%	N/A	TBD	N/A	N/A	N/A	N/A	N/A N/A	
		Level of Compliance with Ontario Regulation 22/04 [1]	NI	NI	NI	NI	C	NI	TBD	C	C	C	C	C	C
		Serious Electrical Incident Index — Number of General Public Incidents	8	6	7	4	5	11	TBD	N/A	N/A	N/A	N/A	N/A	4
		Serious Electrical Incident Index — Rate per 10, 100, 1000km of line	0.066	0.051	0.059	0.033	0.042	0.091	TBD	N/A	N/A	N/A	N/A	N/A	N/A
	System Reliability**	Average Number of Hours that Power to a Customer is Interrupted [2]		6.98	6.88	7.49	7.65	7.83	7.90	7.5	7.0	6.7	6.4	6.1	5.8
		Average Number of Times that Power to a Customer is Interrupted [2]		2.61	2.49	2.70	2.63	2.47	2.30	2.6	2.4	2.3	2.2	2.1	2.0
	Asset Management	Distribution System Plan Implementation Progress*			Under Review	97%	116%	105%	TBD	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	Cost Control	Efficiency Assessment		5	5	5	5	4	TBD	5	5	5	5	5	5
		Total Cost per Customer[3]	$1,072	$1,041	$1,046	$ 1,069	$ 983	$ 987	TBD	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG
		Total Cost per km of Line[3]	$11,064	$10,741	$10,682	$ 10,916	$ 10,198	$ 10,551	TBD	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings[4]					17.27%	42.50%	60.50%***	60.5%	75.9%	88.9%	101.0%	N/A, See Footnote	N/A, See Footnote
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	95.79%	99.39%	100.00%	100.00%	100.00%	100.00%	99.51%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		New Micro-embedded Generation Facilities Connected On Time			99.71%	100.00%	99.78%	99.22%	99.77%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.99	0.99	1.00	0.99	0.97	0.80	TBD	N/A	N/A	N/A	N/A	N/A	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.34	1.30	1.35	1.31	1.19	1.46	TBD	N/A	N/A	N/A	N/A	N/A	N/A
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.30%	9.19%	TBD	N/A	N/A	N/A	N/A	N/A	N/A
		Profitability: Regulatory Return on Equity — Achieved	8.80%	8.72%	8.00%	6.26%	8.77%	8.41%	TBD	N/A	N/A	N/A	N/A	N/A	N/A

Notes:
1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributors' reported information. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future. Since the Framework ends in 2020, the target for this application aligns with the end year of 2020.
*Self-defined metric; no common industry standard.
**System Reliability Measures were restated under the direction of the OEB to exclude both Loss of Supply and Force Majeure - results prior to 2012 were not restated.
***To be verified by the IESO.

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Dx OEB Scorecard

			Historical Results						Actual	Target					
RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2017	2018	2019	2020	2021	2022
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%	72%	74%	75%	75%	76%	76%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	76%	77%	78%	78%	79%	79%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	90%	86%	87%	88%	88%	89%	89%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	78%	81%	83%	84%	84%	85%	85%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	TBD	8,640	8,733	8,908	9,080	9,256	9,437
		Vegetation Management - Gross Cyclical Cost per km $**			New Program				TBD	New Program	3,600	3,643	3,687	2,400	2,428
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	TBD	461,000	454,000	447,000	440,000	434,000	427,000
		OM&A dollars per customer	456	451	498	551	453	455	TBD	449	455	TBD	TBD	TBD	TBD
		OM&A dollars per km of line**	4,723	4,676	5,109	5,654	4,719	4,773	TBD	4,712	4,773	TBD	TBD	TBD	TBD
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,786	8,200	8,200	TBD	TBD	TBD	TBD
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	7,800	6,900	6,500	TBD	TBD	TBD	TBD
		Number of Substation Caused Interruptions	159	144	129	158	141	103	123	145	145	TBD	TBD	TBD	TBD
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.4	9.1	9.0	TBD	TBD	TBD	TBD
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.0	3.4	3.4	TBD	TBD	TBD	TBD
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4	2.8	2.8	TBD	TBD	TBD	TBD
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4	1.7	1.7	TBD	TBD	TBD	TBD
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure	118	147	228	136	162		143	143	TBD	TBD	TBD	TBD

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

**Number of line kms are based on the annual OEB Yearbook of Electricity Distributors' report, with 2017 and 2018 targets based on 2015 line km actuals.

Witness: KIRALY Gregory

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Canadian Manufacturers & Exporters Interrogatory # 15

Issue:

Issue 20: Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?

Reference:

B1-01-01 Section 1.4 Page: 3 Table 8

Interrogatory:

a) To the extent possible, please update the values in table 8 – Distribution OEB Scorecard to include the actuals for 2017, and the variance between 2017 actuals and target.

Response:

a) Provided below is an updated version of Table 8 to include the actuals for 2017, and the variance between 2017 actuals and target. Updated Cost Control measures are not available for 2017 as audited 2017 actuals are not available.

Table 8 – Distribution OEB Scorecard, including actuals for 2017, and the variance between 2017 actuals and target

			Historical Results						Actual	Target		
RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2017	2017 Target Variance	2018
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%	72%	-1%	74%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	76%	0%	77%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	90%	86%	4%	87%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	90%	81%	9%	83%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	TBD	8,640	TBD	8,733
		Vegetation Management - Gross Cyclical Cost per km $**			New Program				TBD	New Program	TBD	3,600
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	TBD	461,000	TBD	454,000
		OM&A dollars per customer	456	451	498	551	453	455	TBD	449	TBD	455
		OM&A dollars per km of line**	4,723	4,676	5,109	5,654	4,719	4,773	TBD	4,712	TBD	4,773
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,786	8,200	586	8,200
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	7,800	6,900	900	6,500
		Number of Substation Caused Interruptions	159	144	129	158	141	103	123	145	-22	145
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.4	9.1	0.3	9.0
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.0	3.4	-0.4	3.4
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4	2.8	-0.4	2.8
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4	1.7	-0.3	1.7
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		118	147	228	136	162	143	19	143

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

**Number of line kms are based on the annual OEB Yearbook of Electricity Distributors' report, with 2017 and 2018 targets based on 2015 line km actuals.

Witness: KIRALY Gregory

Productivity and Outcome Measures Scorecard

Distribution System Plan: Productivity and Outcome Measures

RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2018
			Historical Results						Target	
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 hydro one

Customer Experience

Residential and Small Business Customer Satisfaction Study

December 2016 (Revised February, 2017)

Prepared by: Ipsos

Ipsos

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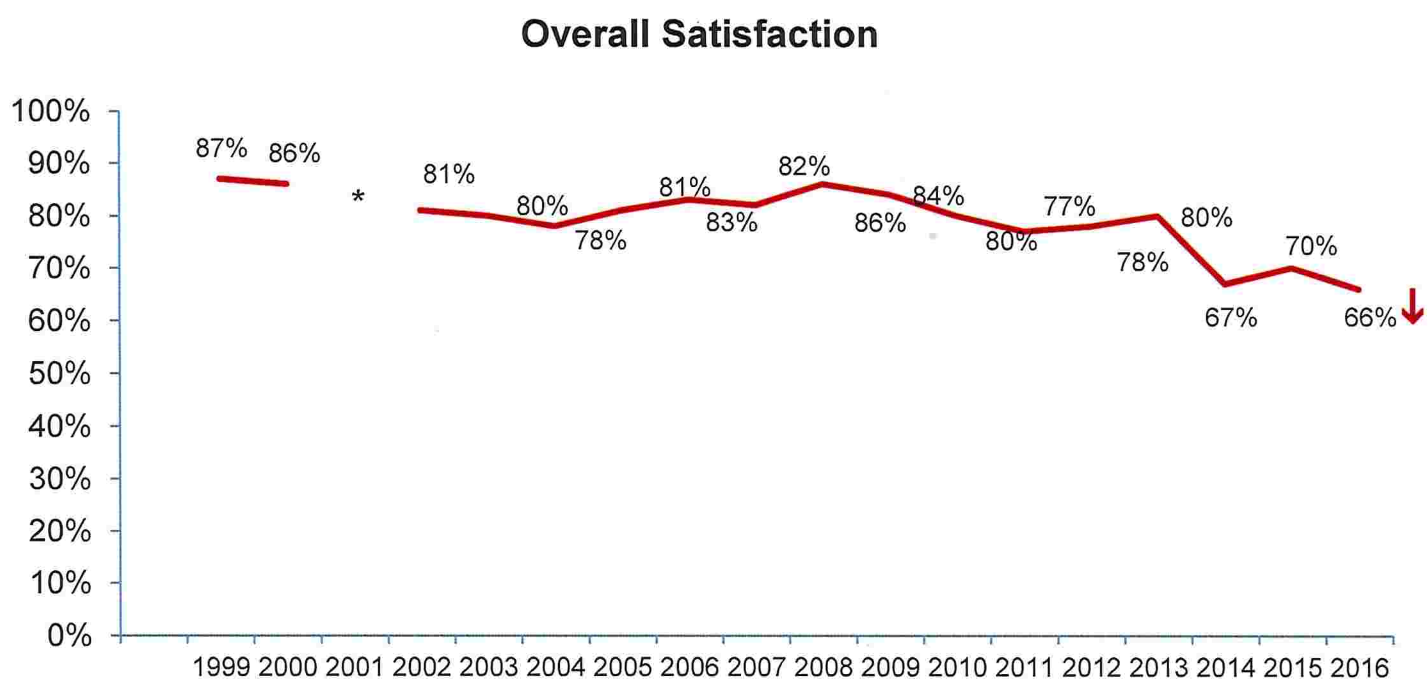
Overall Satisfaction – Survey Results



Key Insights

- *Overall Satisfaction is significantly lower in 2016 compared to 2015.*
- *Rates/Price continues to be the issue mentioned most often by those not satisfied overall with Hydro One. The incidence of mentions has increased significantly to 76% from the 61% found in 2015 – following a steep increase from 2014 to 2015.*

A1 (Q1b). How satisfied are you overall with Hydro One? (5 pt scale) Base: All respondents (n=2,410)
A2B (Q1b1). What issues were you thinking when you rated Hydro One overall satisfaction? (oe) Base: Those who are 'neutral, very or somewhat dissatisfied' in A1 (n=814)
*Study was not conducted in 2001

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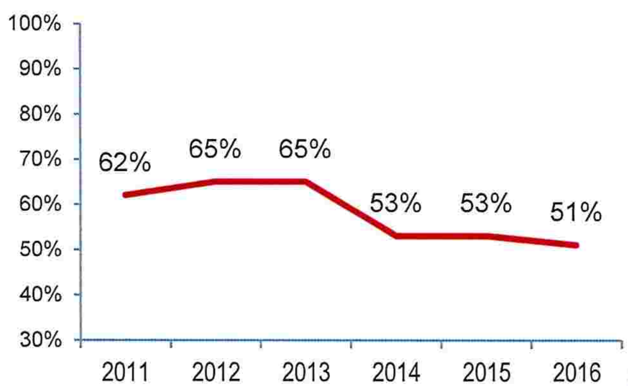
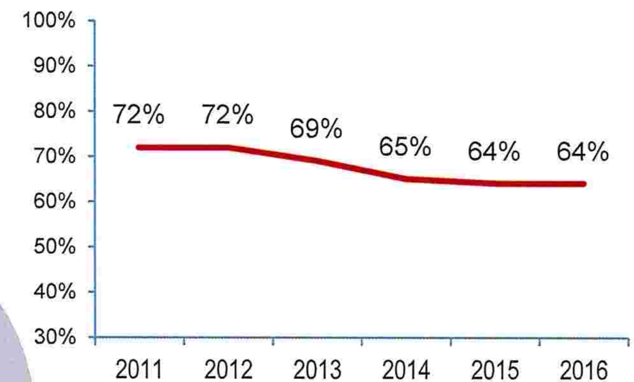
Survey Findings: Drivers of Satisfaction

Despite significant changes in individual metrics in Brand and Price/Billing, the aggregate scores for all groups have remained stable compared to 2015.

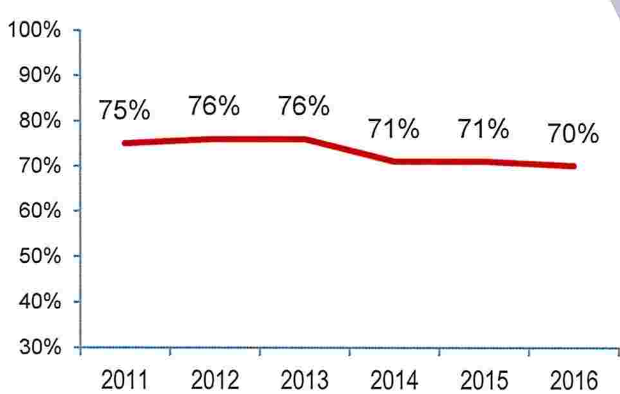
Price/Billing Trend



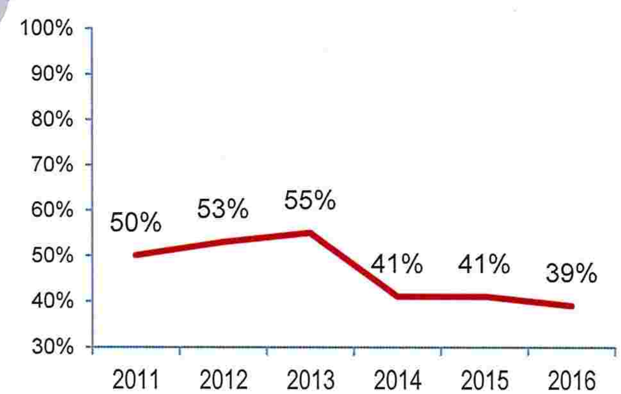
Customer Service Trend



Product Quality/Reliability Trend



Brand Trend



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3.6.2 (5.4.4 – TABLE 2) PLAN VS. ACTUAL VARIANCE TRENDS BY CATEGORY

System Access

From 2013 to 2014 there was an increase in System Access spending of about $40 million. This increase was due to unplanned defective meter replacement, the initiation of the phase out of CDMA technology in meters and collectors and an increase in demand driven customer connection requests. Overall spending across System Access investments for 2015 and 2016 was generally in line with plan levels. However, $42 million above planned spending was caused by an accelerated meter replacement investment. Hydro One planned to phase out CDMA technology in meters and collectors over a five-year period, but this was compressed to two years because a vendor declined to support the technology beyond the two-year window. This increase was offset mostly by a reduction in generation connections. Hydro One had forecast $55 million of connection work, but due to the withdrawal of several connection applications, the actual work completed totalled $23 million.

System Renewal

In 2015, System Renewal projects were $58 million above planned spending. Most of that variance is attributable to the following 4 items. A total of $29 million was due to increased spending on distribution station refurbishment projects to address the high number of stations in poor condition. Increased work on line relocation projects, for the purpose of improving access and reliability, contributed $13 million to the overage. Projects from previous years were under construction and had significant portions carry over into 2015. Increased storm damage and trouble call activity contributed another $14 million to the spending above planned levels.

System Renewal investments for 2016 were $23 million above plan. Spending on storm, trouble call and post-trouble response was the largest source of variance at $22 million above planned levels. Distribution station refurbishments and line sustainment projects, for the purpose of improving access and reliability, accounted for $15 million and $4 million of the overage, respectively. Pole replacement program spending was $5 million less than planned. Additionally, station spare transformer purchases and PCB equipment replacement spending were $12 million and $3 million less than planned, respectively.

The current 2017 forecast for System Renewal investments is $33 million below the previous approved plan due to deferral of the PCB Equipment Replacement Program to future years, a decrease in the Pole Replacement Program, a decrease in Distribution Line Sustainment Initiatives and a decrease in Distribution Station Refurbishments as a result of reprioritized spending into General Plant investments, which are elaborated on below.

System Service

System Service investments were $49 million below planned investment levels in 2015 and $26 million below planned spending in 2016. The 2015 variance is due primarily to a $17 million variance attributable to a delay in the start of the Advanced Distribution System project. Several initiatives of this project were delayed to start in 2016 to align with other related investments. Also, $27 million in 2015 and $25 million in 2016 below planned spending levels were due to a reduction in spending on investments related to distribution system expansion. These investments were reprioritized to accommodate unforeseen increases in other areas of capital spending.

The current 2017 forecast for System Service investments is $43 million below the previous approved plan primarily due to a reduction in investments for System Upgrades driven by load growth as a result of reprioritized spending into General Plant investments, which are elaborated on below.